

**RESERVOIR ENGINEERING GRADUATE
CERTIFICATE - Week 3**
Petrophysics

A special course by IFP Training for REPSOL ALGERIA
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An IFP Training Course for REPSOL

Petrophysics – Rock properties

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Introduction to Petrophysics

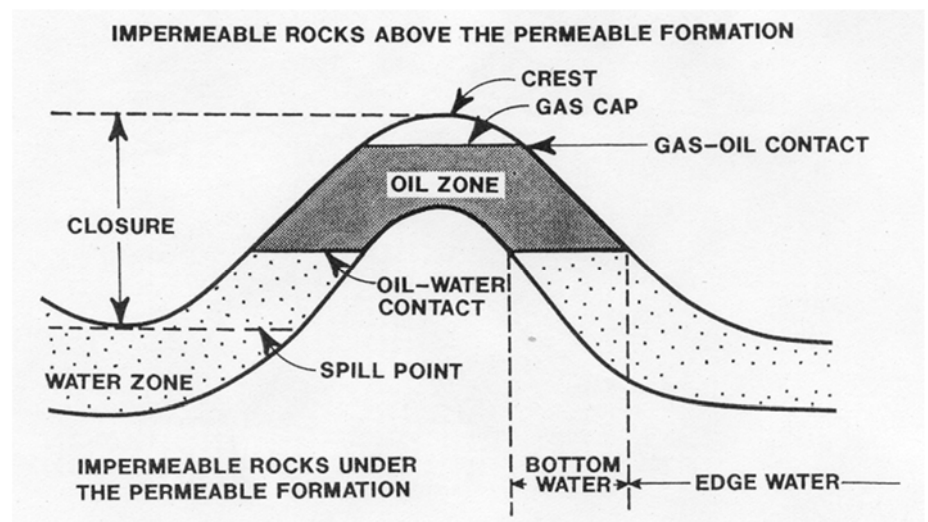
Introduction to Petrophysics Notions of reservoir and trap

► Reservoir

- a porous and permeable formation that contains fluids (water, oil gas, ...)

► Trap: a combination of

- a reservoir impregnated with hydrocarbons,
- overlain by a cap rock (impermeable rock)



Some definitions

► Petrophysics

- Study of rock properties and their interactions with fluids (water solutions, liquid hydrocarbons, gases) (Archie, 1950)

► Accumulations

- Initial volume of hydrocarbons in place (at surface conditions)
 - Original Oil In Place: OOIP
 - Initial Gas In Place: IGIP

► Reserves

- Recoverable volume of hydrocarbon (at surface conditions) with available techniques and under realistic economic conditions

► Recovery Factor = Reserves / Accumulations

Introduction to Petrophysics

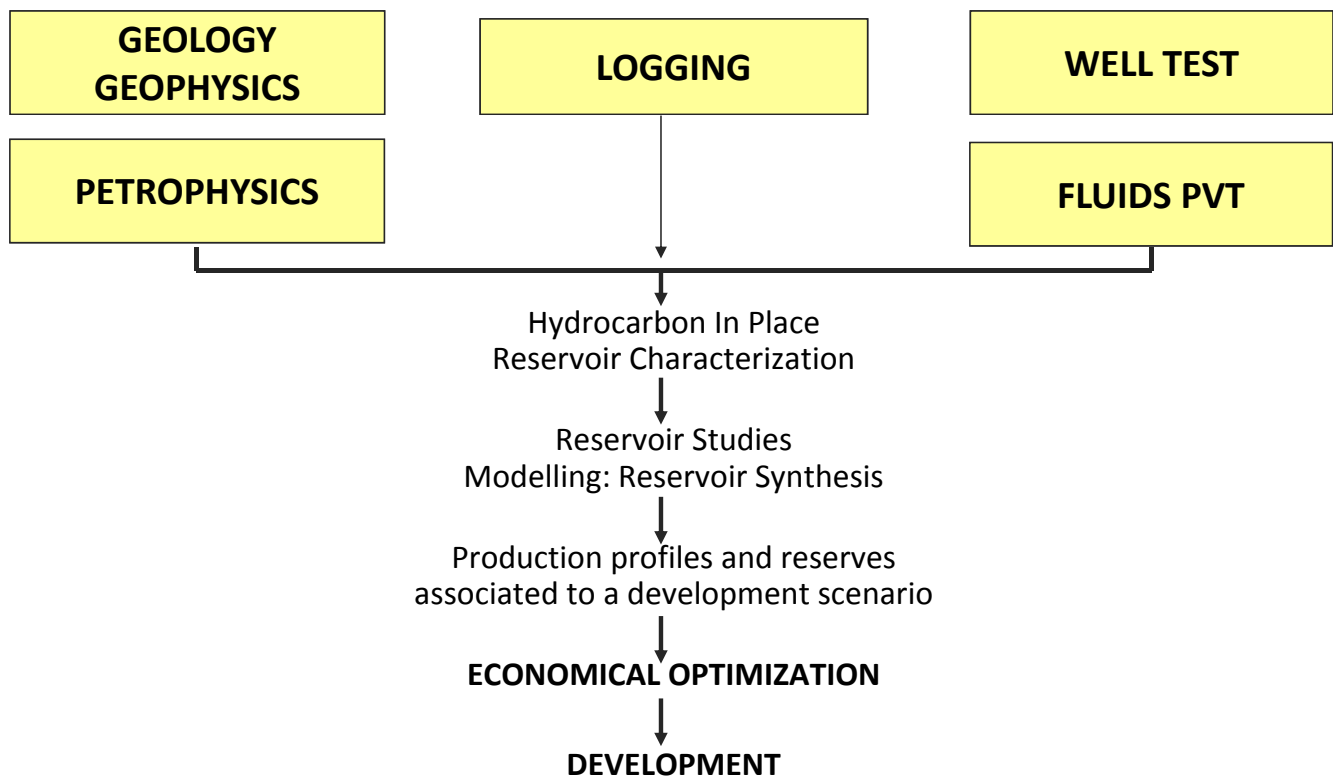
Why Petrophysics?

► Accurate knowledge of petrophysical properties is required to:

- Calculate the accumulations (static)
- Calculate the reserves (dynamic)
- Efficiently develop and manage the oil field through the prediction of future performance

► The behavior of a specific reservoir can only be predicted from the analyses of the petrophysical properties of the reservoir

► The studies of rock properties and of the properties of fluid/rock interactions can be done from samples of the reservoir



► Logging

- Continuous but indirect measurements of properties at reservoir conditions
- **Porosity**: from Neutron (or Sonic) logs, infer ϕ
- **Saturations**: from Resistivity logs, infer S_w then S_o

► Core analysis

- Direct but discrete measurements of properties in laboratory conditions (attempting to reproduce reservoir conditions)
- **Porosity, permeability, saturations, capillary pressure, relative permeabilities** (Conventional Core Analysis / Special Core Analysis)

► Well tests

- Indirect measurements but directly from actual fluid flows in the reservoir
- **Average permeability** within the drainage area of the well



- ▶ **Petrophysics: study of Rock Properties and their interaction with fluids**
- ▶ **Petrophysics studies are mandatory in order to calculate accumulations and reserves and to set up an efficient Field Development Plan**
- ▶ **Petrophysics studies data may be recovered from various techniques:**
 - Logging: continuous and indirect technique which allows to access mainly to porosity and saturation
 - Core analysis: discrete but direct technique which allows to access to porosity, permeability and relative permeability
 - Well Test: discontinuous and indirect technique which allows to access mainly to permeability

Core studies

Core studies

► Geology

- Lithology: Mineralogy – Facies – Depositional environment
- Chronostratigraphy: datations
- Dip, fracturation
- Geochemistry

► Petrophysics

- ρ_b – rock density
- Φ – Porosity
- K – Permeability
- S – Saturation
- Saturation functions: P_c capillary pressure – k_r relative permeability
- Wettability – wettability index
- Rock/pore volume compressibility

► Core-Logs correlations

Core studies

Coring - core recovery

PDC

Poly-
Cristallin
Diamond



TSD

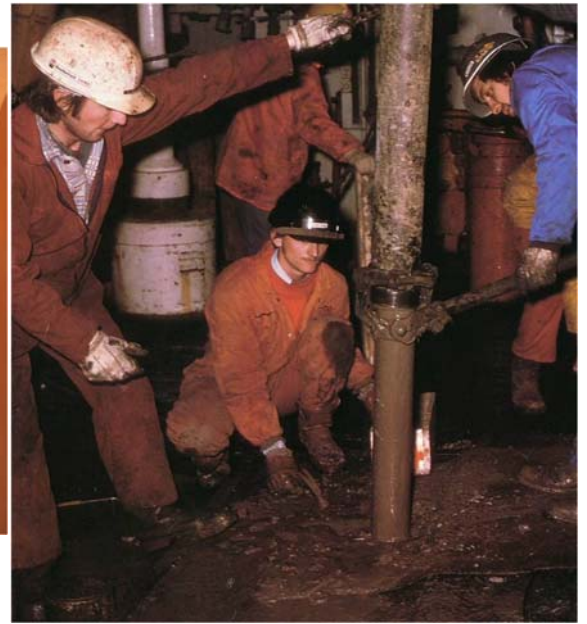
Thermal
Stabilized
Diamond



DIAMOND



Core bits

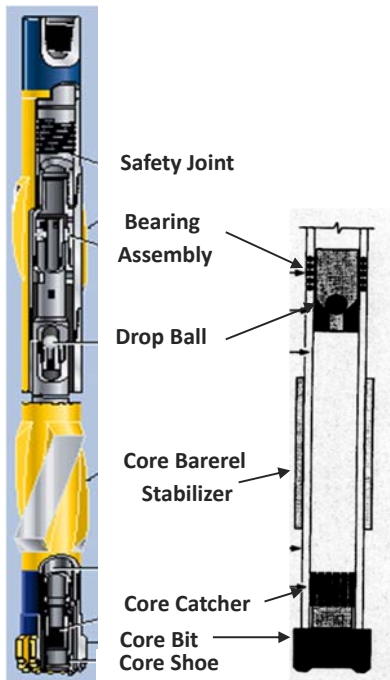


Related issue: contamination of
samples by drilling fluids

Core studies

Coring – how to take cores

Core Barrel



Sidewall Corgun™ (SWC)



- Core Diameter 0.85 in. (21.6 mm)
- Core Length 2.5 in. (63.5 mm)
- Maxi Pressure 20 000 psi (137.9 Mpa)
- Maxi Temp 400 °F (204 °C)

Sidewall Coring Tool (RCORSM)



Bit section of Rotary



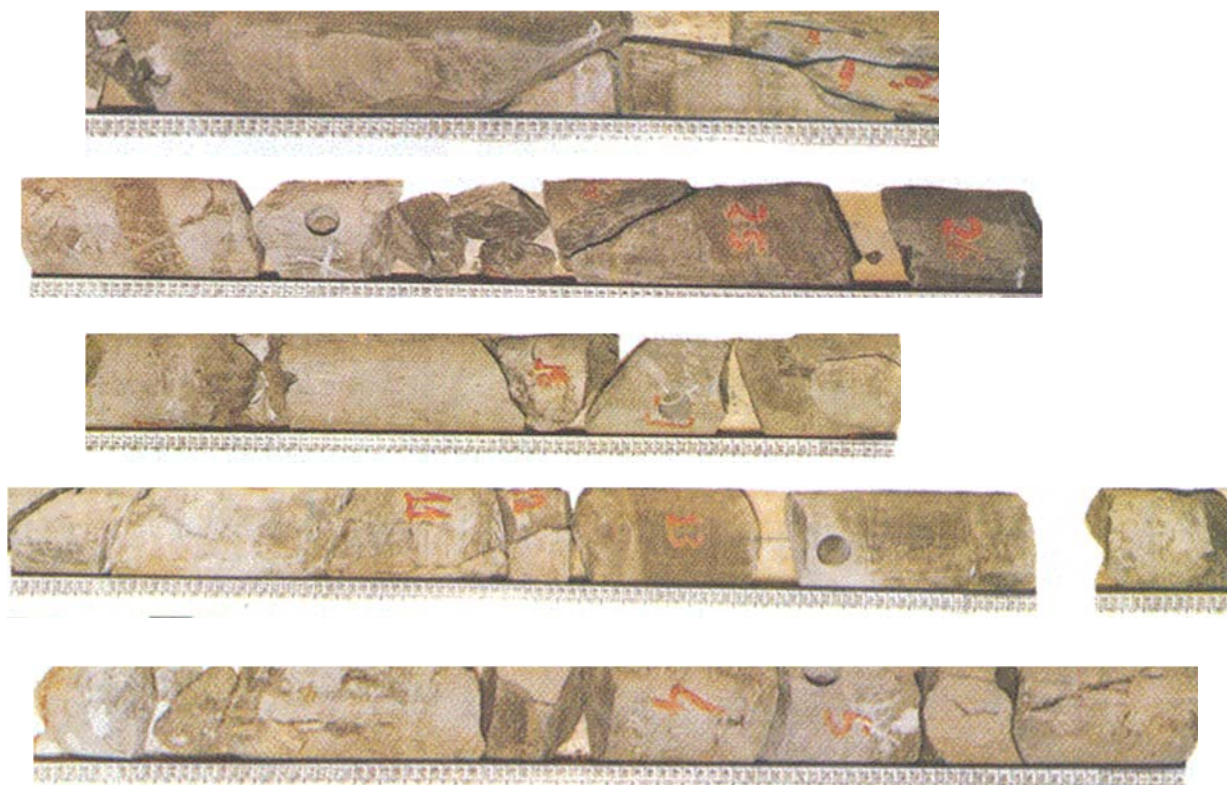
Samples

Core Specifications

- length 1.75 in (44.5 mm)
- diameter 1 in. (25.4 mm)
- capacity 30

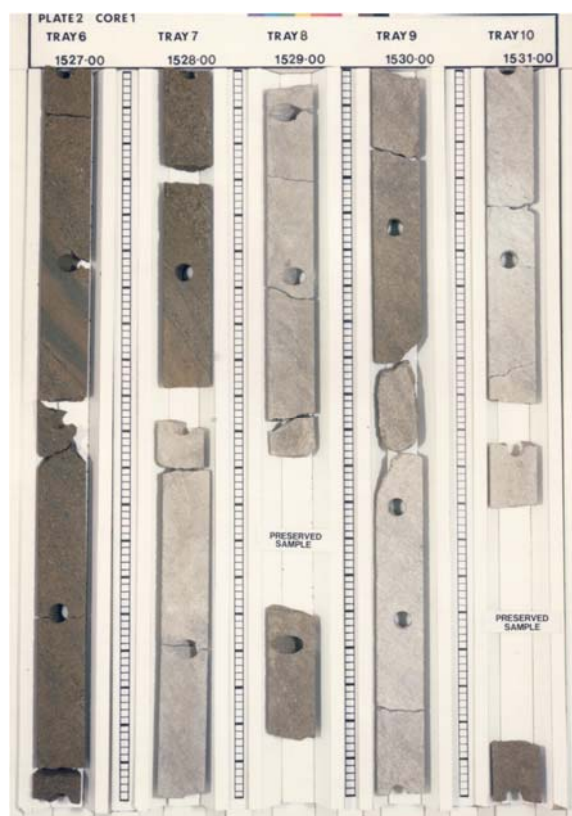
Coring

Examples of cores (1/2)



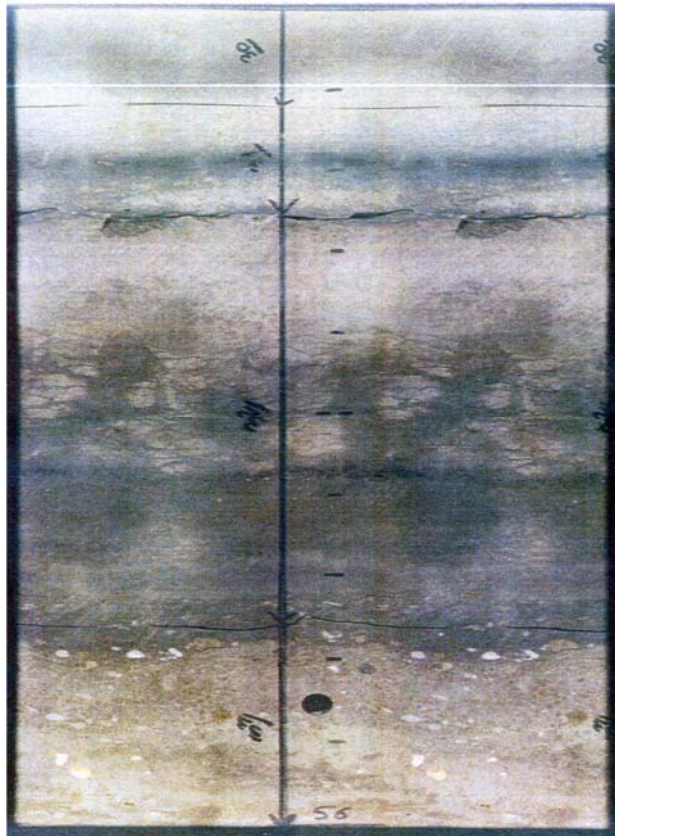
Coring

Examples of cores (2/2)



Core studies

Sandstone



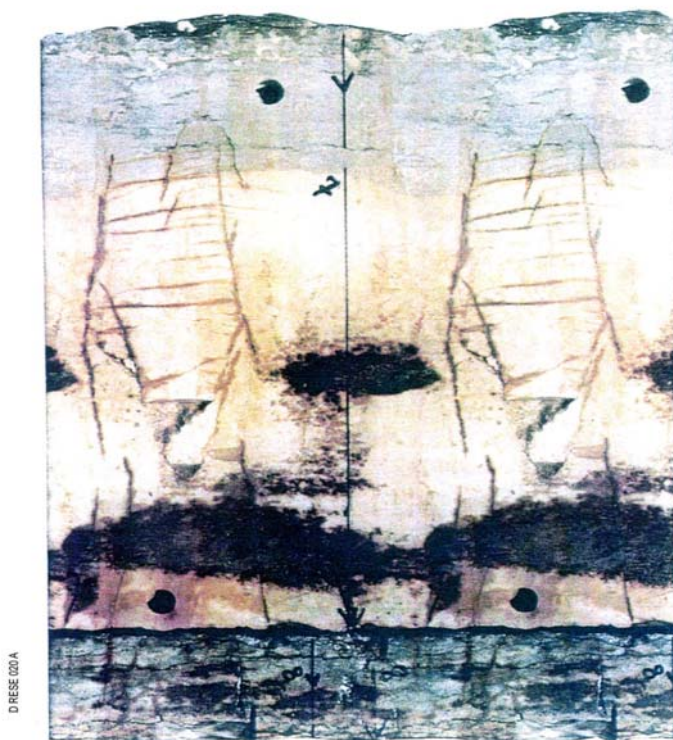
Homogeneous sandstones
=> porosity up to 47%

Shale
=> porosity but no permeability

Heterogeneous sandstones
=> porosity up to 12%

Core studies

Fractured Carbonate



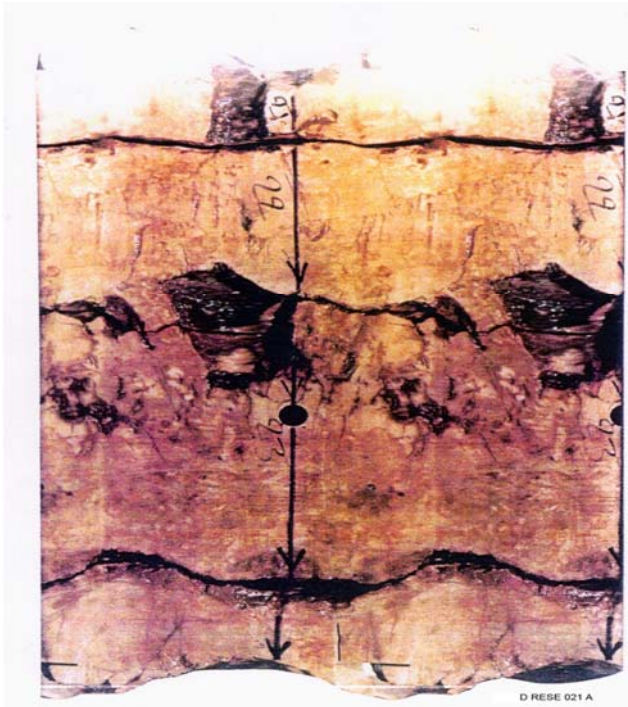
Compact zone

Association of vertical and
horizontal impregnated
fractures

Matrix impregnated with
hydrocarbons
High porosity / low permeability

Core studies

Fractured carbonate



Compact zone

Intense network of small impregnated fractures

Core studies

From field to laboratory

► Petrophysical data acquisition is expensive

- Coring (time rig)
- Cost of experiments

► Petrophysical data acquisition is long

- From the well to laboratory
- Experiments can be long
 - Capillary equilibrium (several weeks)
 - Interpretation of results

► However, it is still the best way to acquire the data necessary to build a reliable reservoir model

From field to laboratory – Representativity of samples

► Morphology of porous network

- It may be altered through
 - Cutting operation
 - Strain relaxation on the sample
 - Extraction
 - Transport
- Consequences: fractures, unconsolidated material
- Effects on porosity \emptyset and permeability k

► Saturations

- They may be altered through
 - Invasion of the sample by the drilling mud
 - Depressurization while rising up the sample
 - Washing the sample on site
 - Poor storage conditions
 - ...
- Effects on fluid saturations S_w and S_o

From field to laboratory – Representativity of samples (2)

► Wettability

- It may be altered through
 - Invasion by drilling mud (surfactants, biocides, inhibitors)
 - Invasion by oil-based mud
 - Depressurization possibly leading to asphaltene deposition
 - Oxidation/pollution during storage
 -
- Effects on the surface properties, nature of the flows and residual saturations
- The phenomenon is generally reversible but getting back to exact initial wettability may be difficult (see below)

► Plugging

- It may occur through
 - Invasion by drilling mud
 - Clay swelling by hydration
 - Salt precipitation either in the reservoir or at the surface (washing the sample with incompatible water)
- Effects on the permeability k (and porosity \emptyset)

From field to laboratory – Recommendations (1)

► During coring operations

- Drilling parameters (weight on bit, rotation,...) adapted to lithology
- Selected drilling mud (specific weight, composition,...)
 - Water-based mud (WBM) may help to avoid wettability alteration
 - Oil-based mud (OBM) may help to avoid clay swelling
- Extraction, on-site washing, storage, transport
 - No shock at extraction
 - No washing with water-shoot on site
 - No temperature variation: may cause condensation/evaporation (transportation is delicate for unconsolidated samples)
- Preservation of samples
 - Aluminum foils
 - Resin coating
 - Freezing (unconsolidated samples)
- No sawing

From field to laboratory – Recommendations (2)

► Conventional core measurements

- Mainly to determine ϕ , k , S and matrix (rock) density
- Normalized plug ($\Phi=23\text{mm}$ $L=23\text{mm}$)
- Large number of plugs
 - Frequency: 1 to 4 per meter if homogeneous
 - Possibly more if heterogeneous

► Special core measurements(plug $\Phi = 10\text{cm}$ $L = 10$ to 30cm)

- Mainly to determine capillary pressure curve, relative permeability curves, wettability, Archie's coefficients (a , m , n) and pore volume compressibility
- Necessary to characterize petrophysical facies
- They take heterogeneities and the related scales into account

From field to laboratory – Heterogeneities

► Various sources of heterogeneity

- Progressive or sudden granulometry variation
- Variation of the amount of rock cementation
- Laminations, oblique or cross bedding
- Variation of lithology: clay, carbonates, sandstone content ...
- Vugs (in particular for dolomitic formation)

► Take into account various scales of heterogeneities

- Metric to decametric : reservoir
- Centimetric and below: laboratory samples

From field to laboratory – Heterogeneities (2)

► Various sources of heterogeneity

- Stylolites and closed micro fractures by recrystallization of minerals => barriers to flow



- Naturally open fractures or fractures incompletely filled by recrystallization minerals => preferential flow path
- Fractures induced by drilling during coring or later handling
 - In the sample but not in the reservoir!



▶ Rotary coring

- Sampling while drilling
- Is the sample representative?
 - Possible contamination by drilling fluid
 - Possible deposition or precipitation of solids/fluids
 - Strain relaxation

▶ Objective

- To have a look at the structure of the subsurface and to spot zones of interest
- To provide samples in order to determine the main petrophysical properties (porosity, permeability, capillary pressure curve, relative permeabilities, ...) and define lithofacies and petrofacies (=> determination of rock-types)

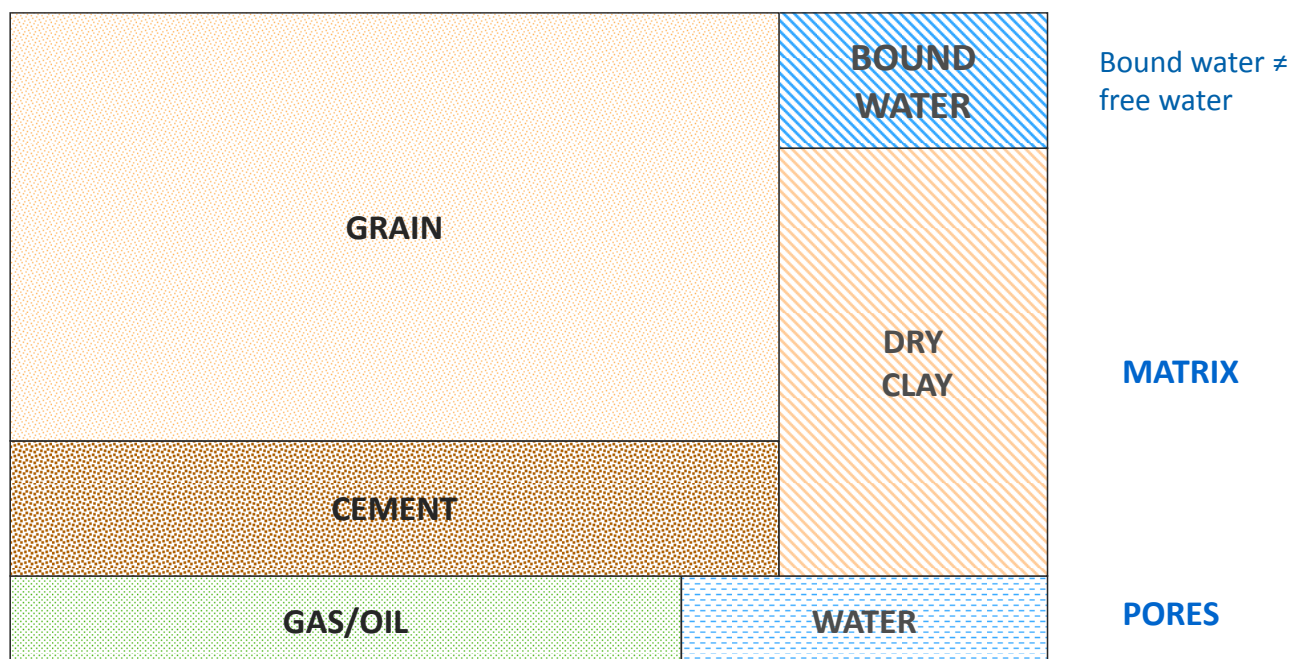
▶ Drawbacks and advantages

- It may be long (several months for core experiments) and expensive
- It allows to get reliable data provided the representativeness of samples is maintained

Porosity, Saturation, Electric Measurements

Porosity

Distribution of components in an elementary volume



Porosity: $\phi = V_p/V_t = (V_o + V_w)/V_t$
with V_p = pore volume V_t = total volume

Porosity

Definition

- ▶ Porosity is defined as the void fraction i.e. the ratio of the volume of the voids (or pores) within the porous medium to the total volume

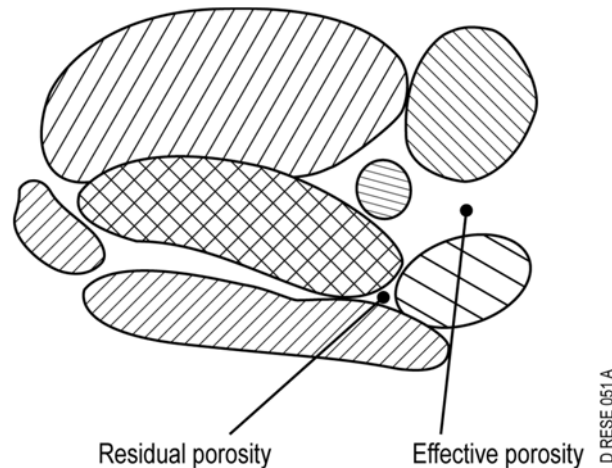
$$\phi = V_{\text{pores}} / V_{\text{total}} = (V_{\text{total}} - V_{\text{rock}}) / V_{\text{total}}$$

- ▶ Several types of porosity

- Effective porosity: connected porosity
- Total porosity: connected and residual porosity
- Residual porosity generally considered to be negligible but it can be untrue especially for carbonates

- ▶ Ranges

- $\phi < 5\%$ poor - typically tight carbonates
- $10\% < \phi < 20\%$ normal
- $\phi > 20\%$ good - typically sandstones – chalk



Porosity

Driving parameters

- ▶ Main parameters

- The **grain shape** and their **organization**
- The **distribution** of the grain sizes

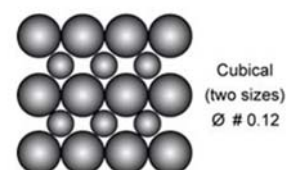
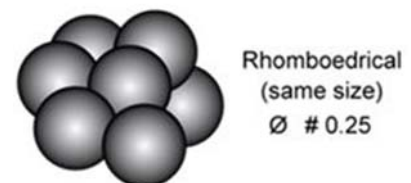
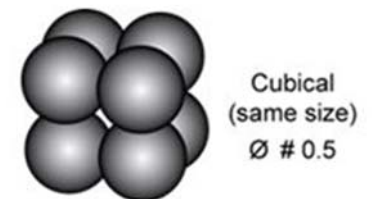
- ▶ Porosity is **not** related to the grain size for a given assembly of equal-sized spherical grains

- ▶ In natural porous media ϕ is also affected by:

- Consolidation, compaction, erosion,...
- Chemical leaching,
- ...

- ▶ Typical values depending on lithology

- Sandstones 10 – 40 %
- Calcites and Dolomites 5 – 25 %
- Clays 20 – 50 %
- Silt 35 – 50 %
- Shale 0 – 10 % (e.g. Bakken $\phi \sim 5\%$)



► Porosity is

- Derived from log interpretation (typically Density-Neutron logs, NMR logs, possibly Sonic log)
- Directly measured on core samples in laboratory

► Core analysis measures effective porosity only (i.e. connected porosity)

► Logs measure total porosity (effective + residual)

- It is very often assumed that residual porosity can be neglected

► Measurements from logs have to be compared to core analysis results on a few wells in order to be validated

- Once validated, porosity from logs can be used on the wells for which we do not have cores
- In case of significant differences between core and logs porosity
 - Check log calibration (especially in the case of Sonic)
 - Check possible heterogeneities
- Core is generally the reference

► Reminder

$$\phi = V_{pores}/V_{total} = (V_{total} - V_{rock})/V_{total} = 1 - V_{rock}/V_{total}$$

► We need to measure:

- The total volume:
 - directly by measuring the dimensions of the sample
 - by measuring a volume of fluid displaced by the sample provided the fluid does not enter the sample (coating with paraffin)
 - by using mercury
- The rock volume:
 - by immersion in a solvent - but may be long and is intrusive
 - by using an expansion chamber and Boyle-Mariotte's law

Porosity

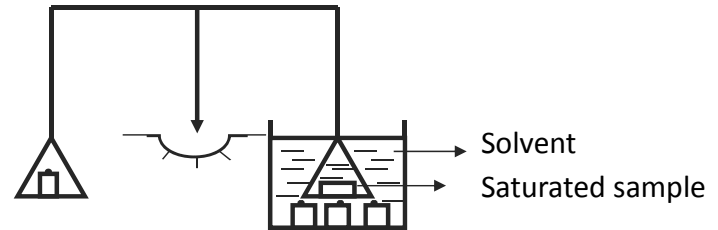
Measuring solid volume

► Solvent imbibition method

- Sample saturated by the solvent

$$V_s = \frac{P_{dry} - P_{immersed}}{\rho_{solvent}}$$

- Drawbacks
 - May be long (in order to reach complete saturation of the sample)
 - Intrusive

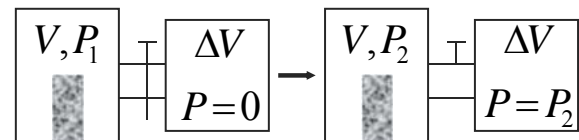


► Gas expansion method

- A dry sample is put in a chamber of volume V at pressure P_1
- Valve is open with expansion chamber of volume ΔV and pressure drops to P_2
- Boyle-Mariotte's law:

$$(V - V_s)P_1 = (V - V_s + \Delta V)P_2$$

$$V_s = V - \frac{P_2}{P_1 - P_2} \Delta V$$



Porosity

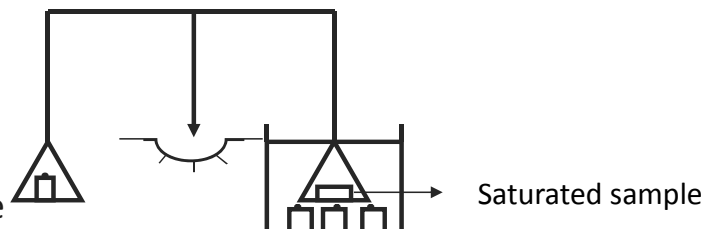
Measuring pore volume

► Liquid weighting

- Sample saturated by the liquid (brine)

$$V_p = \frac{P_{saturated} - P_{dry}}{\rho_{solvent}}$$

- Gives access to the connected pore volume
- But may be long and is intrusive



► Mercury Injection (MICP)

- Increasing injection pressure allows mercury to enter smaller and smaller pores
- It gives access both to bulk volume and connected (effective) pore volume
- Rapid (a few hours)
- But it is intrusive and mercury may never completely invade all the connected pores => default value of V_p

► Gas Expansion

- By measuring directly the expansion of the air contained into the pores and applying Boyle-Mariotte's law
- Fast and accurate

Porosity

Matrix density

- Generally calculated together with porosity

$$d = \frac{\text{dry weight}}{\text{rock volume}} \text{ (g/cm}^3\text{)}$$

- Some values:

- sandstone: 2.65 - 2.67
- limestone: 2.70 - 2.76
- dolomite: 2.82 - 2.87
- shale: 2.64 - 2.66
- salt: 2.14

Porosity

NMR Nuclear Magnetic Resonance



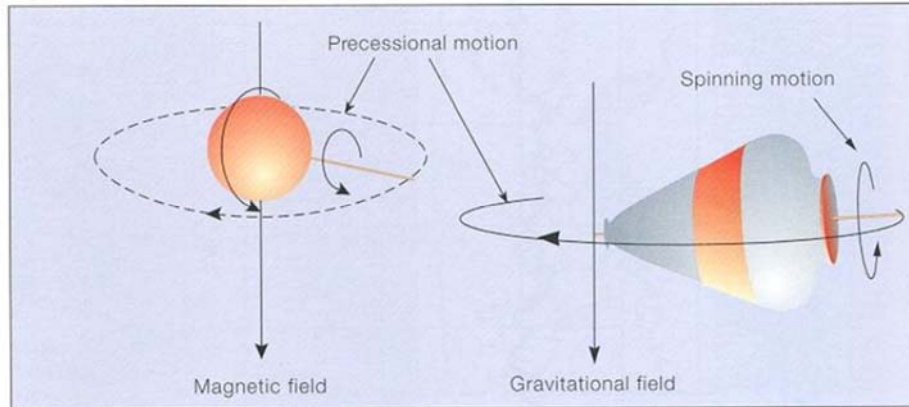
$T_{\max} = 10-100^{\circ}\text{C} \text{ (50-212}^{\circ}\text{F)}$



Principle of NMR - 1

► NMR is based on two properties of hydrogen atom nuclei i.e. protons

- The magnetic moment i.e. the proton ability to align itself parallel to a magnetic field
- The nuclear spin i.e. the proton rotation by respect to an axis much like a gyroscope



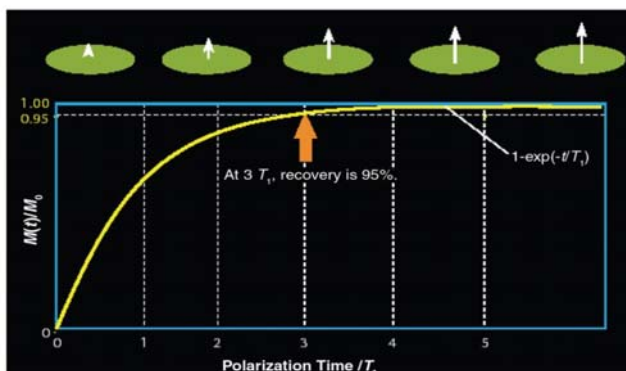
From Oilfield review – 1997

Protons disturbed from equilibrium precess in the magnetic field the same way a spinning top precess in the Earth gravitational field

Principle of NMR - 2

► Longitudinal relaxation

- Applying a strong magnetic field will cause the protons to align parallel to the field; once the field is turned off, the protons will return to their initial chaotic state
- The return to initial state is not instantaneous and it follows an exponential decay leading to **the longitudinal (or spin-lattice) relaxation time T_1**
- T_1 is related to **the time needed for the protons to align with the magnetic field** (63% of polarization is reached at T_1 , full polarization at five T_1) and directly to pore size and fluid viscosity

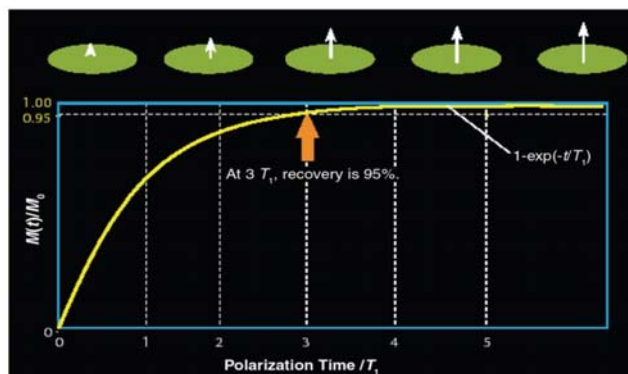


Polarization of protons within a magnetic field

From PEH

► Transverse relaxation

- When aligned, the protons are submitted to an oscillating perpendicular magnetic field created by short time bursts of radio frequency energy
- The protons are tipped into a perpendicular plane to the polarizing magnetic field and begin to precess around its, all of them in phase => **Nuclear Magnetic Resonance**
- When the oscillating magnetic field is turned off, the precessing protons begin to dephase and the transverse signal (or Free-Induction Decay) decays exponentially leading to **the transverse (or spin-spin) relaxation time T_2**
- T_2 is directly linked to pore size but may also help to determine fluids nature



After a short 90° pulse, the protons begin to dephase and the FID signal is detected

The initial precession frequency is called the Larmor frequency and is proportional to the polarization field strength

From PEH

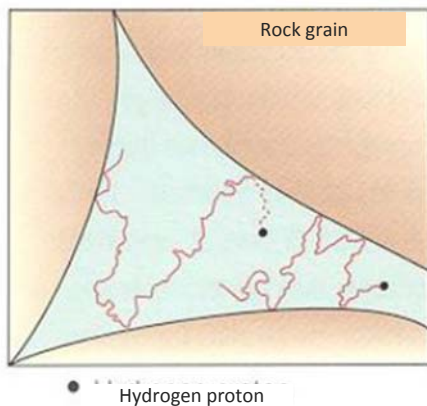
► NMR analysis is mainly based on the analysis of **transverse relaxation**

- Transverse relaxation is faster than longitudinal decay because of additional dephasing

► Transverse relaxation has three origins

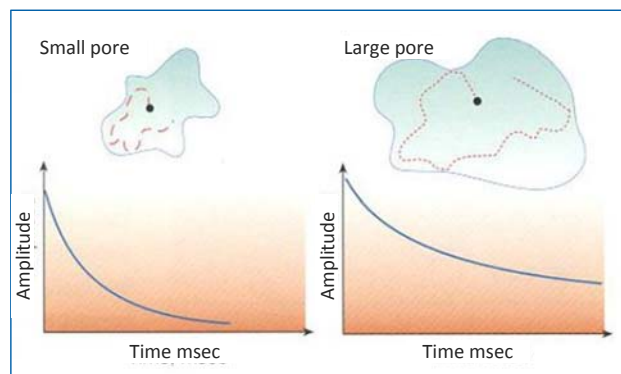
- **Intrinsic** : bulk relaxation in the fluid far from the pore wall (or in the matrix)
 - Due to spin-spin magnetic interaction between neighboring protons
 - Controlled by fluid viscosity, composition, temperature and pressure
 - The more viscous the fluid, the shorter the relaxation time
- **Surface** : relaxation at the fluid-solid interface between a wetting fluid and the pore wall
 - Due to interaction between fluid protons and surface at atomic level
 - Dramatically decreasing relaxation times (both T_1 and T_2) and main contributor to T_2
 - The smaller the pores, the higher the surface relaxation effect and the shorter T_2
 - In the case of a non-wetting fluid within the pores, it continues to relax following its own bulk relaxation
- **Diffusion** : slight increase in relaxation time because of diffusion that prevents correct phase adjustment
 - Diffusion effect is dominant for gas and helps to identify it

NMR analysis – 2 surface relaxation



Principle of surface relaxation: the interaction between protons and pore walls may cause relaxation
From Oilfield review – 1997

Effect of pore size on surface relaxation: small pores increase the probability of the protons to collide with pore walls thus decreasing T_2 relaxation time
From Oilfield review – 1997



NMR analysis – 3

► T_2 equation

- The three relaxation processes are independent and each has its own contribution

$$\frac{1}{T_2} = \frac{1}{T_{2,bulk}} + \frac{1}{T_{2,surface}} + \frac{1}{T_{2,diffusion}}$$

- Assuming the diffusion effect is negligible (typically the case of brine filling the pores)

$$\frac{1}{T_2} = \frac{1}{T_{2,bulk}} + \frac{1}{T_{2,surface}}$$

$$\frac{1}{T_2} = \frac{1}{T_{2,bulk}} + \rho_2 \frac{S}{V}$$

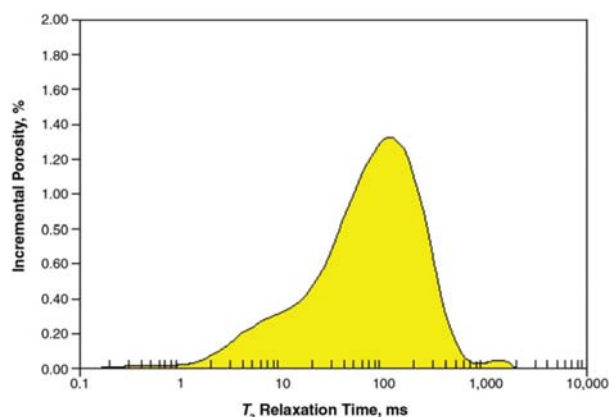
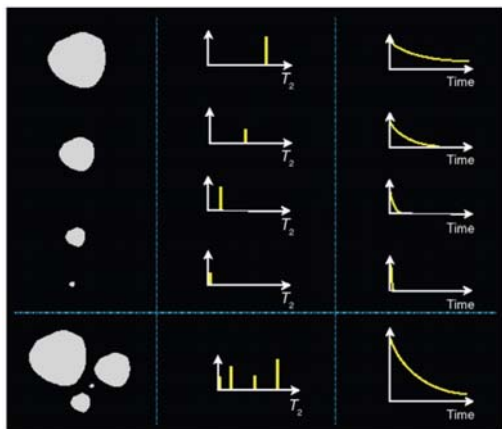
With ρ_2 the relaxivity of the surface and S/V is the ratio surface/volume of the pore

Surface relaxivity depends on the mineralogy of the grain

S/V can be interpreted as a measurement of the pore size; **the larger the pore size, the larger T_2**

► Pore size distribution

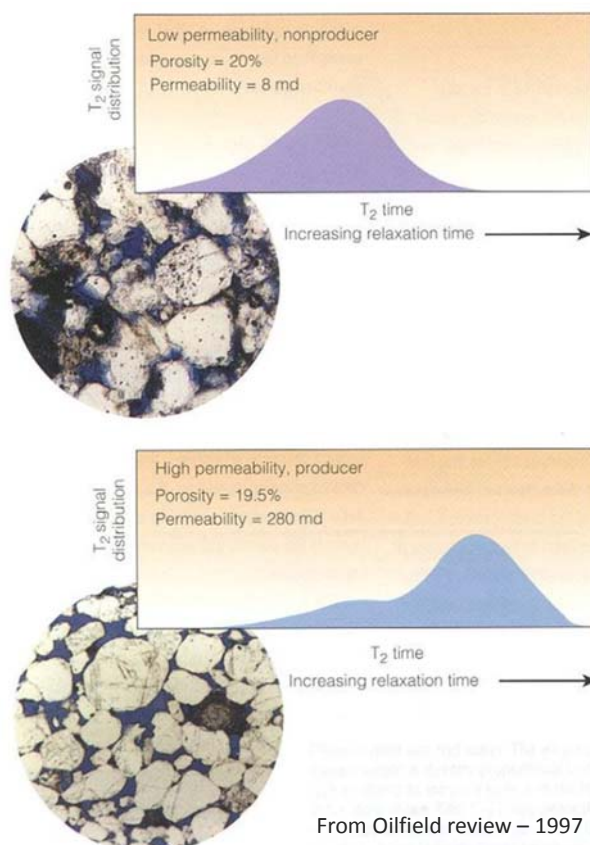
- From the previous equation, within brine-filled pores, one pore size is associated to one value of T_2
- However, porous media show various pore sizes and the resulting NMR T_2 signal is the sum of the signals emitted by each pore => the signal is multi-exponential and has to be processed for identifying the various T_2 and hence the various pore sizes => **there are several solutions!**



Composition of T_2 due to pores of various sizes and corresponding T_2 distribution rebuilt from mathematical processing From PEH

► From T_2 distribution

- The integral of the T_2 curve gives the total porosity**
 - It is possible to get the same porosity from very different distributions
- Each value of T_2 corresponds to one size of pore => the distribution of T_2 gives the distribution of pore size and an indication about permeability (see below)
 - Distributions with small T_2 imply small pores with large surface-to-volume ratio and typically low permeability
 - Distributions with large T_2 imply large pores with small surface-to-volume ratio and typically high permeability



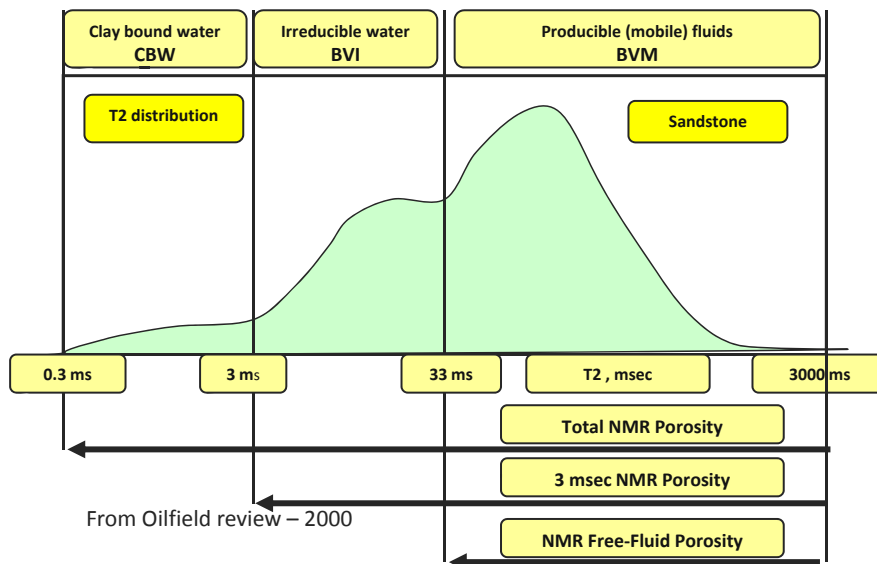
From Oilfield review – 1997

► From T_2 distribution, information about producible and non-producible fluids

- Especially NMR gives access to **CBW** (Clay Bound Water), **BVI** (Bound Volume Irreducible) and **BVM** (Bound Volume Mobile) which is a measurement of movable fluid (water and oil) in the pore volume and **FFI** (Free Fluid index)

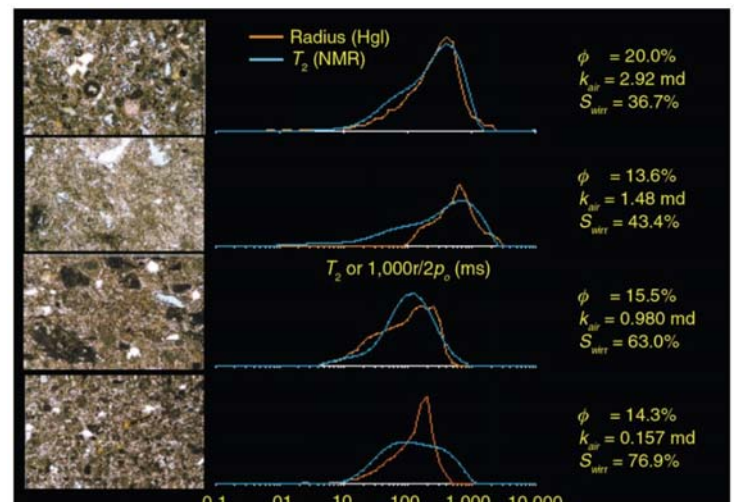
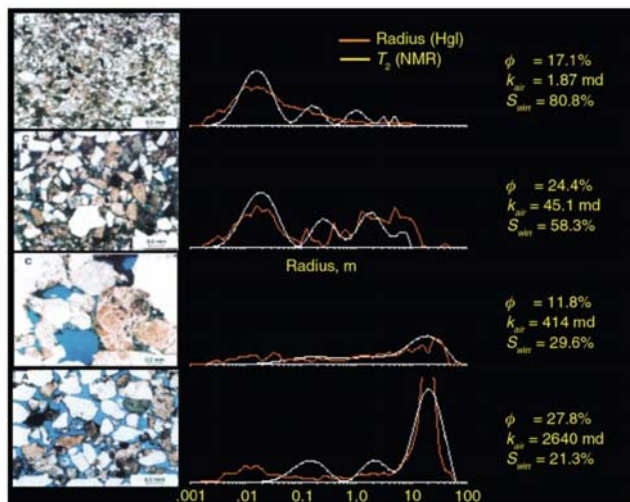
$$FFI = \phi(1 - S_{wirr}) = \phi - BVI \cong BVM \text{ (if CBW is negligible)}$$

where ϕ is the porosity and S_{wirr} is the irreducible water saturation



► NMR results from T_2 distribution analysis have been confirmed by Mercury Injection

- However NMR is about pore size while mercury injection is about pore throat size!



Correlation between NMR and Mercury Injection distribution in brine-saturated sandstones (left) and carbonates (right)
From PEH

Saturation

Definition

- ▶ By definition, a fluid saturation is the percentage of pore volume filled with this fluid
- ▶ Assuming the pore volume is fully saturated with fluids

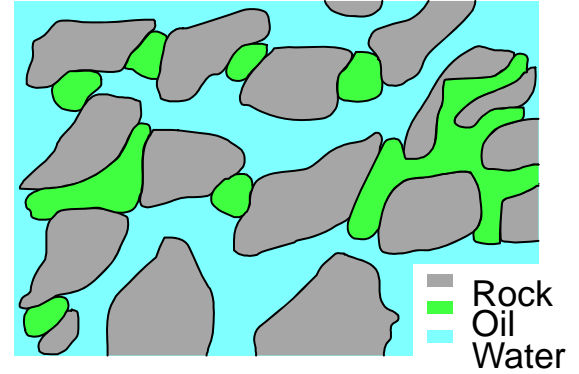
$$V_{water} + V_{oil} + V_{gas} = V_{pores}$$

- ▶ Hence

- Water saturation: $S_w = V_w/V_p$
- Oil saturation: $S_o = V_o/V_p$
- Gas saturation: $S_g = V_g/V_p$

- ▶ By definition

$$S_w + S_o + S_g = 1$$



Saturation

Saturations in the reservoir

- ▶ Fluid saturations in the reservoir may vary widely, especially as a function of height
- ⇒ **Saturation profile** that has to be determined as accurately as possible
- ▶ The saturation profile has a strong influence on the accumulation
 - It will depend on the nature of the porous network, especially the size of the pores and the size of the pore throats
 - It will strongly depend on the wettability (see below)
- ▶ Saturations may be measured either directly from cores or from logs
 - Generally, log measurements are the reference since core measurements are difficult to perform and mostly inaccurate

► From cores: two main methods

- Evaporation of the fluids within the pore space => **retort method**
 - Sample is sealed in a cell and temperature is increased by stages up to 600°C
 - Advantages: fast (one day or less) with the possibility of treating several samples in parallel
 - Drawbacks: vaporization losses, oil coking, recuperation of bound water (=> empirical corrections have to be made), destruction of the sample
- Leaching the fluids within the pore space => **Dean-Stark extraction method**
 - Use a solvent vapor to flow through the core and leach out water and oil
 - A typical solvent is toluene, which is miscible with oil but not with water
 - The water condenses and is collected while the mixture of solvent and oil continuously cycles all along the extraction process; it stops when the volume of extracted water remains constant
 - Advantages: accurate and non destructive
 - Drawbacks: very slow (several days to weeks!) and some residual oil may be bypassed by the solvent
- But possible alteration due to coring process (depressurization) and drilling fluid invasion

► From logs

- Resistivity or induction logs (cf. logs)

Electric measurements

Resistivity measurements

► The relationship between electrical properties and reservoir characteristics is fundamental to quantitative evaluation of the formation

- It is the basic principle of OH electric logging carried out on almost all the wells

► Resistivity is narrowly linked to the main constituents of the reservoir

- Rock: solids present in the rock are generally non conductive => infinite resistivity
- Hydrocarbons: very few conductive => high resistivity
- Water: is a conductor when it contains dissolved salts => low resistivity

► The total resistivity depends on fluid saturations and porosity

=> Estimation of in-situ S_w (and correspondingly hydrocarbon saturation) is possible but it needs calibration by laboratory measurements

Formation factor

► Formation factor

$$F = R_o / R_w$$

Where R_o is the electrical resistivity of the sample saturated with brine

And R_w is the electrical resistivity of the brine occupying the same volume than the sample

- Generally $F > 1$

► Other expression of the formation factor (by Archie)

$$F = a / \phi^m$$

With m the cementation exponent

And a the tortuosity coefficient

- Typically we get $1.3 < m < 2.5$ while a depends on the porous medium

Electric Measurements

Cementation exponent

► Cementation exponent

- Also called **porosity exponent**
- Models the increase in the resistivity due to the porous network, the rock itself being assumed to be non conductive (infinite resistivity)
- If the porous network is modeled by a set of parallel capillary tubes, a cross-section area averaged resistivity of the rock is dependent on the porosity $\phi \Rightarrow m = 1$ but the tortuosity of the rock leads to values of $m > 1$
- Sands
 - Unconsolidated : $m \cong 1.3$ but value increases with cementation
 - Consolidated : $1.8 \leq m \leq 2$
- Carbonates
 - The variability of m is stronger due to much more complex porous structures et diagenesis influence $1.7 \leq m \leq 4.1$

Resistivity index – Archie's law

► Resistivity index

$$RI = R_T/R_O = R_T/(F \cdot R_w) = S_w^{-n}$$

Where R_T is the electrical resistivity of the sample at S_w

And n is the saturation exponent

► Saturation exponent

- Effect of desaturating the porous medium and replacing a conductive fluid (water) by a non-conductive fluid (hydrocarbons)
- It depends on the wettability
 - For a water-wet system, even for low values of S_w , there will still be a film of water at the surface of the rock, thus ensuring a good value of conductivity $\Rightarrow n \cong 2$ and constant with S_w (Archie's rocks)
 - For an oil-wet system, the continuity of the water film will be interrupted by oil droplets and conductivity will decrease \Rightarrow higher values of n up to 8
- For complex rocks like carbonates, n varies with S_w

Electric measurements

Archie's law

► Archie's law

$$S_w = \left(F \cdot \frac{R_w}{R_T} \right)^{1/n} = \left(\frac{a}{\phi^m} \cdot \frac{R_w}{R_T} \right)^{1/n}$$

- Default values are $a = 1$, $m = n = 2$

► In the aquifer

- $S_w = 1 \Rightarrow$ we can deduce R_w

$$R_w = \frac{R_T}{F}$$



► Porosity

- Defined as the percentage of void in the rock i.e. the ratio of pore volume to the total rock volume
- It depends on the grain shape and organization and on the distribution of the grain sizes but not on the grain sizes themselves
- Effective porosity = connected porosity / residual porosity = unconnected porosity
- Estimated from core data or logging interpretation; reference is core data
- Measured through immersion in a solvent (but may be long and intrusive), mercury injection (same problems) or gas expansion (GEX); NMR gives information about pore size distribution and more (especially about irreducible water saturation)
- The typical range of values in conventional reservoirs is from a few % up to 25-30%

► Saturation

- Defined as the percentage of a given fluid volume within the pore volume
- It may be measured from cores but results may be unrepresentative because of problems of core conservation – typically measured from logs

Electrical measurements



► Resistivity measurements

- A measurement of the electrical resistivity of the formation along the well
- They depend on fluids and saturations
- They may give access to water saturation S_w

► Archie's law

$$S_w = \left(F \cdot \frac{R_w}{R_T} \right)^{1/n} = \left(\frac{a}{\phi^m} \cdot \frac{R_w}{R_T} \right)^{1/n}$$

- a is the tortuosity factor
- m is the cementation exponent
- n is the saturation exponent
- By default, $a = 1$, $m = n = 2$ but actual values may be quite different leading to different estimate of S_w

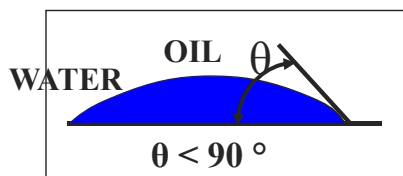
Wettability and Capillary Pressure

Wettability

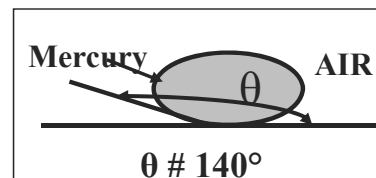
Definition

► Wettability

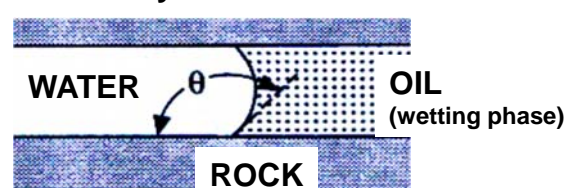
- Tendency of one fluid to spread over a solid surface in presence of another fluid
- Characterized by a **contact angle**
- Function of surface chemistry i.e. **fluid-rock system**



Water-wet system



Oil-wet system



Wetting fluid: contact angle $\theta < 90^\circ$

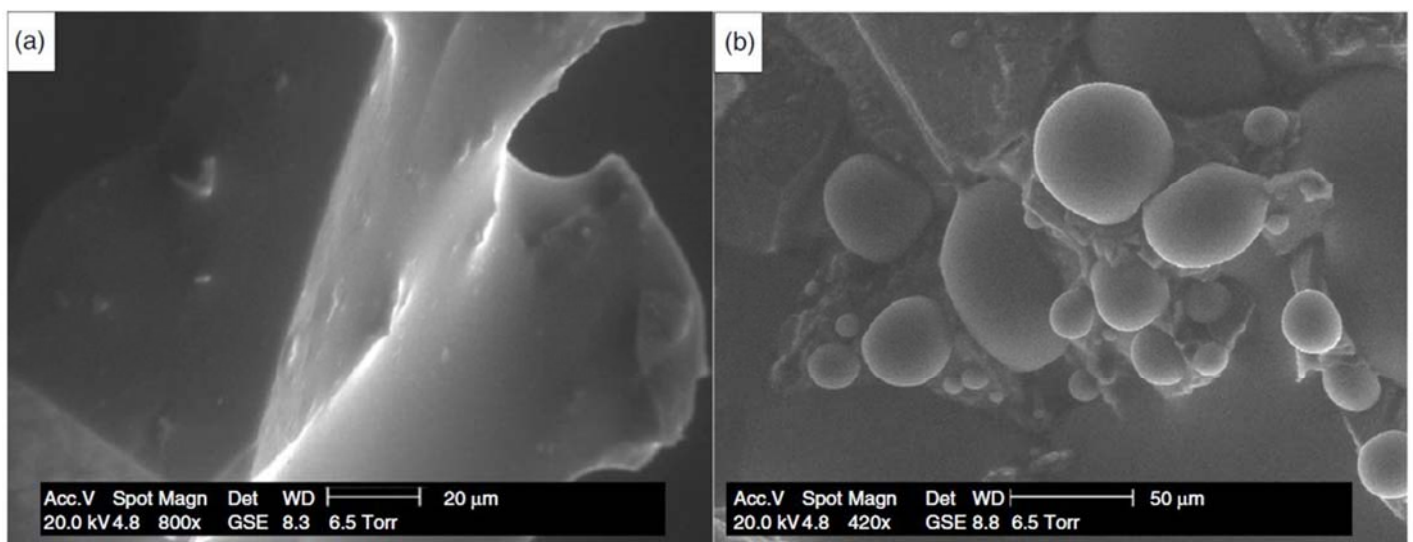
Wettability to oil is due to polar components in oil or to adsorbed products on the rock surface

In a rock/brine/oil system **wettability measures the preference of the rock either for oil or water**

Wettability of porous media

- ▶ **Wettability determines which fluid will be in contact with the rock surface**
 - **Water-wet reservoirs:** water covers the rock surface, oil occupies the bulk of large pores
 - Contact angle typically between 0 and 75 degrees
 - **Intermediate-wet or neutral-wet reservoirs:** no preference for either fluid
 - Contact angle typically between 75 and 105 degrees
 - **Oil-wet reservoirs:** oil covers the rock surface, water occupies the bulk of large pores
 - Contact angle typically between 105 and 180 degrees
 - **Fractional-wet reservoirs:** due to wettability alteration, parts of the reservoir are water-wet while others are oil-wet
 - **Mixed-wet reservoirs:** fractional wet reservoirs into which the oil-wet surfaces form continuous parts typically through the largest pores while the smaller pores remain water-wet (and possibly without oil inside)
- ▶ **Wettability refers to the wetting preference of the rock and not to the fluid in contact with the rock at a given moment**
 - A sample of clean sandstone saturated with oil will be coated by oil but may still be water-wet... or not since the contact of oil with the rock may alter surface properties...

Wettability



Environmental Scanning Electronic Microscope pictures of thin sections

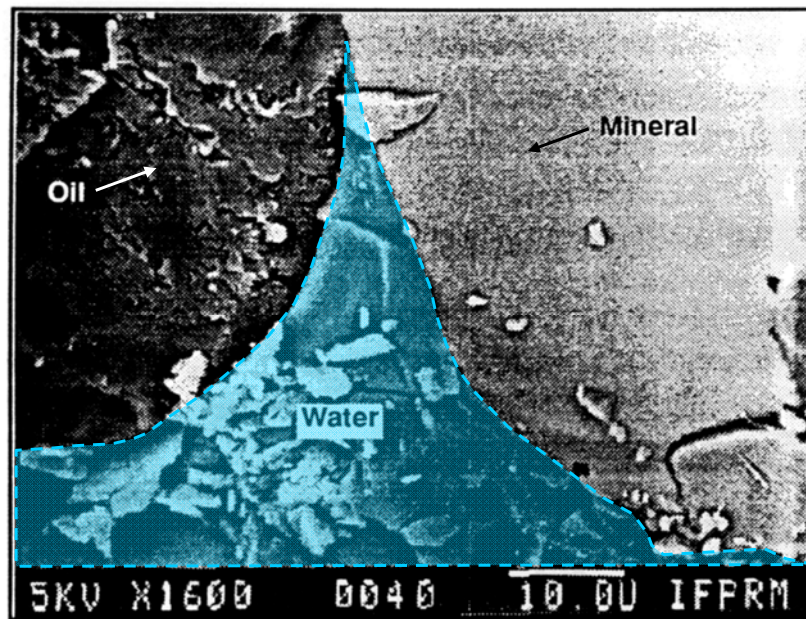
- (a) Initial strongly water-wet rock: the water forms film at the surface of the grain
- (b) Mixed-wet rock after ageing through soaking with a crude oil: the water now forms droplets of various sizes and contact angles at the surface of the grain => change in wettability due to the adsorption of organic materials at the surface of the grains

From Jahanbakhsh & al. *SPE Reservoir Engineering & Evaluation Journal*, 2016

Wettability

Water-wet vs oil wet (SEM)

WATER-WET
reservoir?



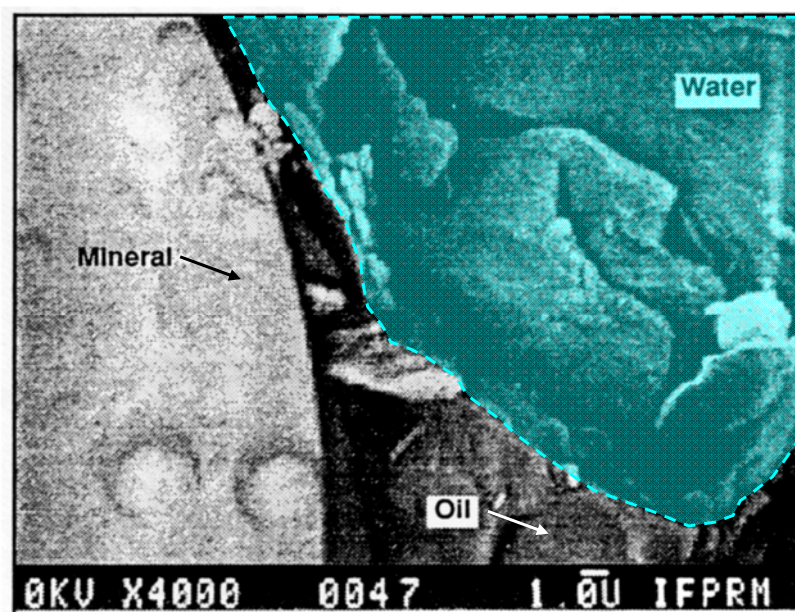
OIL-WET
reservoir?

Scanning Electron Microscope picture – from IFPEN

Wettability

Water-wet vs oil wet (SEM)

OIL-WET
reservoir?



WATER-WET
reservoir?

Scanning Electron Microscope picture – from IFPEN

Reservoir wettability

- ▶ **Historically, all reservoirs were considered to be water-wet**
 - Most of clean sedimentary rocks are strongly water-wet
 - Sandstones reservoirs are deposited in aqueous environment with oil migrating later and it was assumed that these reservoirs may remain water-wet

- ▶ **In the 40's, first evidence of oil-wet reservoirs arose and systematic wettability measurements demonstrated that oil-wet reservoirs did exist and were not exceptions (Elf, Amoco, BP, IFP)**

- ▶ **Currently, most reservoirs are considered to be mixed-wet or even oil-wet**
 - Clean sandstones reservoirs are thought to be rather water-wet but shaly sandstones may be mixed-wet or oil-wet ; clay may also turn the wettability to mixed- or oil-wet
 - Carbonates reservoirs are thought to be rather mixed-wet or oil-wet

Wettability

Factors affecting wettability - 1

- ▶ **Oil composition**
 - Oil may contain **natural surfactants** containing molecules like oxygen, nitrogen or sulfur
 - Natural surfactants have an hydrocarbon and a polar end, **the latter one adsorbing on the rock surface** and thus exposing the former one hence leading to an oil-wet surface
 - Natural surfactants can be found mostly in the heavier fractions of crudes, **like resins and asphaltenes** which are prone to alter wettability towards mixed- or oil-wet
 - The composition of the oil (SARA) has a strong influence since, if the oil is a poor solvent for its own surfactants, it will alter wettability more easily

- ▶ **Rock mineralogy**
 - Carbonates are typically more oil-wet than sandstones
 - **Silica are negatively charged at pH above 2** while **calcites are positively charged at pH below 9.5** thus, at near neutral pH, silica will be adsorbing positively charged groups while calcites will be adsorbing negatively charged groups
 - Amines may react with silicates and increase water-wet character while carboxylic acids may react with carbonates and increase oil-wet character (or decrease water-wet character)

Factors affecting wettability - 2

► Brine composition

- **Salinity** and **pH** of brine play a major role since they affect the electrical charge of rock surface and fluid interface
- At near neutral pH, silica will adsorb cationic surfactants while calcites will adsorb anionic surfactant but this may change for calcites at relatively high pH (>9.5-9.8)
- The presence of multivalent cations in the brine, typically Ca^{2+} , Mg^{2+} , Ba^{2+} , Ni^{2+} , Fe^{3+} may increase the oil-wet character
 - The cations may act as **activators**, adsorbing on the rock surface and facilitating the adsorption of surfactant agents like fatty acids (in the case of silica e.g. quartz) thus turning wettability from water to oil
 - They may also **combine** with the surfactants to form **a positive cationic surfactant-metal complex**, which is then adsorbed on the negatively charged surface
 - Very few cations are necessary to observe a significant action on wettability (a few ppm)

► Temperature

- A higher temperature may increase the oil-wet character of silica
- A higher temperature may increase the water-wet character of calcites

Factors affecting wettability - 3

► Wettability may be affected during the life of the reservoir

► Drilling fluids may have a near-well impact

- Oil Base Mud typically contains surfactants and may locally increase wettability to oil (or decrease wettability to water)

► Injecting water with different dissolved salt content and/or pH may change wettability

- This an EOR method!

► Pressure depletion during production may affect wettability

- By changing crude composition
- By causing apparition of free gas within the reservoir
- By possibly causing asphaltenes deposition within the reservoir

Influence of wettability

► Wettability plays a major role by affecting

- Capillary pressures
- Saturations
 - Irreducible water saturation
 - Residual oil saturation
- Relative permeabilities

► Thus wettability affects both the distribution and the flow of fluids within the reservoir

- **Saturation profiles are very different depending on wettability**
 - In the case of water-wet reservoir, transition zone (cf. below) may be large with maximum oil saturation at the top
 - In the case of oil-wet reservoir, the maximum oil saturation will be at the bottom with no transition zone but it will decrease up in the reservoir!
- **Wettability has a strong influence on the Recovery Factor**
 - Heterogeneity in wettability, due for instance to variation of lithology, may have a strong influence on Secondary Recovery or EOR process efficiency

Laboratory determination of wettability

► Several methods available

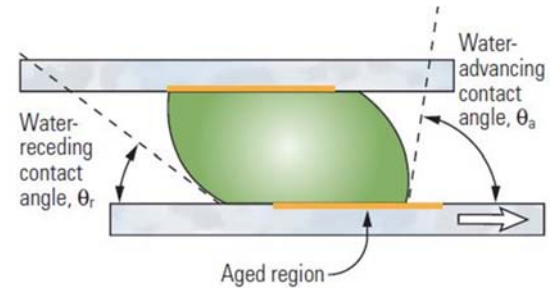
- **Amott-Harvey method**: based on the amount of fluid absorbed by a rock sample through a spontaneous and a forced imbibition (see below)
- **USBM method**: same principle as Amott-Harvey but with the determination of work needed to perform a forced fluid displacement within a rock sample (see below)
- **Direct microscopic observation** using a SEM may allow to observe wettability and determine contact angles but it is still very difficult to perform
- **Glass slide method**: displacement of the non-wetting fluid on a glass slide ; it may allow to determine contact angle
- **Flotation method**: from the distribution of grains at water-oil or air-water interface
- **Imbibition** (see below)
- **From relative permeability curves** (see below)

► Standard industry methods are Amott-Harvey and USBM

- Both of them give so called **wettability index**
- **Quantitative** but **not absolute**: they may be used mostly to compare/rank the wettability of various core plugs

Contact angle method - 1

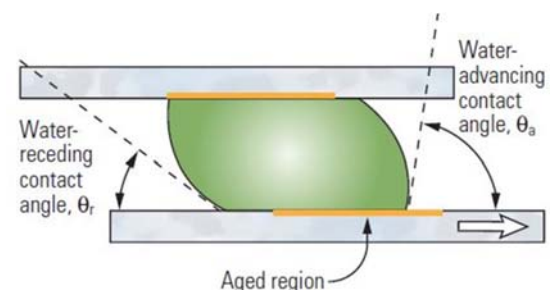
- ▶ **Direct measurement of the contact angle by displacement of the non-wetting fluid**
- ▶ **Various methods**
 - Tilting plate, sessile drop, modified sessile drop, etc.
- ▶ **Method**
 - Using oil, simulated formation brine (ionic composition!) and model surfaces typically polished mineral crystals (quartz for sandstones and calcite for carbonates)
 - Aging is required before and after the crystal has moved for the contact angles to stabilize (generally several tens of hours)
 - After stabilization, two contact angles are measured: the **water-advancing contact angle** θ_a and the **water-receding contact angle** θ_r



From Abdallah & al - Oilfield Review 2007

contact angle method - 2

- ▶ **Main drawbacks**
 - **Reproducibility**
 - The measurement of contact angle is subject to **hysteresis**
 - The contact-angle hysteresis given by $\theta_a - \theta_r$ can be higher than 60° !!! and θ_a and θ_r are considered to be very reproducible...
 - **Representativeness**
 - Contact angle methods cannot take into account roughness, heterogeneity of the rock surface (e.g. presence of clay within sands) and complex geometry of reservoir rocks
 - It is assumed that the oil will change the crystal surface conditions to the real formation conditions...



From Abdallah & al - Oilfield Review 2007

► Other qualitative methods

- Flotation method
 - Distribution of sand grains at water/oil interface => the grains will move preferably towards one of the two-phase thus indicating the wettability
 - Only for strongly wet systems
- Relative permeability methods
 - Based on the effect of wettability on relative permeability (cf. below)
 - Only for strongly wet systems
- Displacement capillary pressure

$$P_{cd} = \frac{2\sigma \cos \theta_a}{r_{max}}$$

where θ_a is the apparent contact angle and r_{max} is the radius for which the non-wetting fluid begins to enter the pores

Practically, two measurements are made, typically oil/water/rock and oil/air/rock => assuming that oil is completely wetting the rock in the oil/air/rock system (i.e. $\cos \theta_a = 1$ in this case) it is possible to get θ_a for the oil/water/rock system

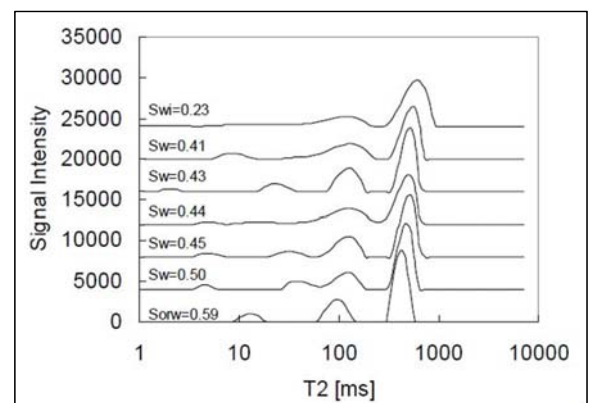
► When using NMR, depending on the wettability of the sample, a shift in T_2 peak is observed as a function of the fluid saturation

For instance, for mixed-wet or oil-wet systems, as oil saturation decreases towards oil residual saturation, oil will remain only at the surface of the bigger pores thus reducing the value of V_{eff} and decreasing the surface relaxation time T_2 :

$$\frac{1}{T_{2,surf}} = \rho_2 \frac{S}{V_{eff}}$$

With ρ_2 the relaxivity of the surface
 S the surface area of the pore contacted by the fluid of interest

V_{eff} the volume of wetting-phase fluid within the pore



From Johannesen & al – Society of Core Analysts 2007

Wettability alteration

- ▶ **Ideally, laboratory experiments should be carried out with core wettability identical to reservoir in-situ wettability but many parameters may alter the core wettability**
- ▶ **Alteration before testing**
 - **Drilling fluids:** OBM may contain surfactants, pH may be different from reservoir fluids
 - **Trip-out:** since pressure and temperature decrease, light ends are expelled and asphaltenes may deposit
 - Packaging, preservation: loss of light ends, water evaporation, oxidation
 - **Cleaning:** may alter the amount and type of material adsorbed on the rock surfaces
- ▶ **Alteration during testing: test fluids, temperature, pressure**
 - It may cause asphaltenes and waxes to precipitate and coat pore surfaces
 - Increase in temperature tends to increase the solubility of wettability-altering compounds => cores are generally more water-wet at reservoir conditions than in laboratory conditions
 - Best practice: to use live fluids at reservoir pressure and temperature but it is expensive!!

Wettability alteration – Getting representative cores

- ▶ **Core wettability may not be representative of reservoir wettability**
- ▶ **Three options to get representative cores**
 - **Native-state (fresh) cores:** trying to maintain the wettability of in situ rock
 - Choice of drilling fluids: reservoir evaluation concerns against drilling issues and economics
 - Trip-out: ... almost uncontrollable problem
 - Packaging: well site preservation, not appropriate for selection of representative samples
 - Follow-up: requires a strong involvement of the lab team all over the process
 - **Cleaned core:** removing contamination from adsorbed compounds
 - Rock is left strongly water-wet => should be used only when reservoir is known to be water-wet
 - It is often difficult, if not impossible to remove all the adsorbed materials
 - Performed with refined oils, at room temperature and pressure
 - Cheap and fast process (routine from service companies)
 - **Restored-state core:** core is first cleaned and then returned to its original wettability
 - Step 1 : check wettability with Amott or USBM tests
 - Step 2: Flow brine then reservoir oil into the cores: reservoir fluids are needed!
 - Step 3 : Aging the core at reservoir temperature for 2/3 weeks then check wettability with Amott or USBM tests

Interfacial Tension - Definition

► Interfacial tension (IFT) σ

- The surface energy existing between two immiscible fluid phases such as oil and water
- The force per unit length required to create more surface (interface) by bringing molecules from the interior of one phase into the surface region

► Interfacial tension creates an energy barrier preventing one fluid to mix with another

- The higher the IFT, the less miscible the two fluids
- IFT is nil for two miscible fluids

► Unit: dyne/cm or N/m

- $1 \text{ dyne/cm} = 1 \text{ mN/m} = 10^{-3} \text{ N/m}$

Capillary Pressure

Interfacial Tension – Properties

► Interfacial tension depends among others on pressure and temperature, aging, fluid composition etc.

► Example on IFT of dead-oil/brine and live-oil/brine systems for a Lower Cretaceous Carbonate reservoir:

- For dead-oil/brine system: IFT decreases with increasing temperature (pressure kept constant) and increases with increasing pressure (temperature kept constant)
- For live-oil/brine system: IFT increases with increasing temperature (pressure kept constant)
- IFT showed a significant increase with aging

► Interfacial tension may be modified, typically lowered, by using **surfactants**

- Bipolar products presenting typically an **hydrophilic** end and an **hydrophobic** end
- Surfactant put themselves at the interface, creating some kind of « bridges » between the two non miscible phases and thus decreasing the interfacial tension

► Typical values

- In the reservoir
 - Oil-water σ_{ow} 15-40.10⁻³ N/m
 - Gas-water σ_{wg} 35-60 .10⁻³ N/m
 - Gas-oil σ_{og} 0-15.10⁻³ N/m
- Laboratory
 - Air-brine σ_{wa} 72.10⁻³ N/m
 - Mercury-air σ_{Hg-air} 480.10⁻³ N/m

► Measurement

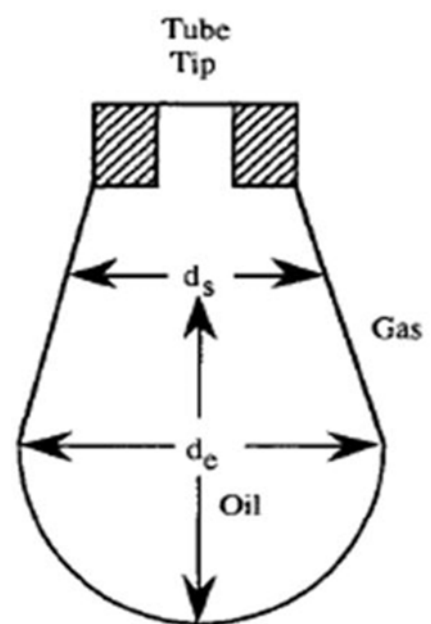
- Pendant drop method: optical analysis of the geometry of the drop gives the corresponding IFT value
- Du Noüy ring method: measurement of the force necessary to slowly raise a ring from the surface of a liquid

► Principle:

- A liquid droplet is allowed to hang from the tip of a capillary tube in a high pressure visual cell filled with its equilibrated vapor
- The shape of the liquid droplet at static conditions, i.e. at equilibrium between gravity and surface force, is determined and related to IFT:

$$\sigma = g \frac{d_e^2}{H} \cdot \Delta\rho$$

with $H = H(d_e, d_s)$ the correction factor
and $S = d_e/d_s$ the shape factor



Pendant drop method

► Reservoir conditions

$$P_{max} = 500b (7252psi)$$

$$T_{max} = 150^{\circ}C = 302^{\circ}F$$



From IFPEN

Capillary Pressure

Notion of Capillary Pressure

► Capillary pressure

- Pressure difference between two non-miscible fluids in equilibrium in a capillary tube
- Pressure difference in a capillary medium **between the non-wetting fluid and the wetting fluid**

► Laplace's equation (for a capillary tube)

$$P_c = P_A - P_B = \frac{2\sigma \cos \theta}{r}$$

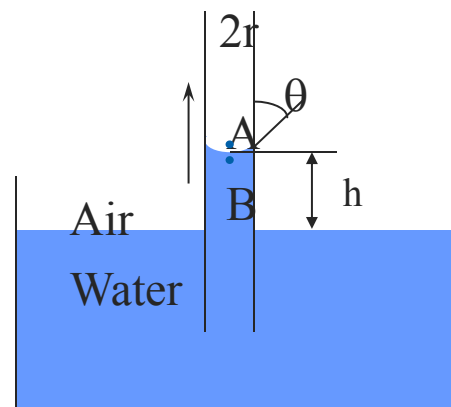
As $P_B + \rho_w gh = P_{atm} + \rho_{air} gh$

And $P_A = P_{atm}$

Then

$$P_A - P_B = (\rho_w - \rho_{air})gh$$

$$P_c = \frac{2\sigma \cos \theta}{r} = (\rho_w - \rho_{air})gh$$



Capillary Pressure

Parameters affecting Capillary Pressure

► From Laplace's equation, capillary pressure depends on:

- **Wettability** (θ)
=> depends on the **rock – fluids system**
- **Pore diameter** (r)
=> depends on the **porous medium**
- **Interfacial tension** (σ)
=> depends on the **fluids system**

► Possible fluids systems in the reservoir

- Gas is always the non-wetting phase, oil can be the wetting or the non-wetting phase
- Water-oil system: $P_c = P_o - P_w$
 - $P_c > 0$ in the case of water-wet system
 - $P_c < 0$ in the case of oil-wet system
- Gas-oil system: $P_c = P_g - P_o$
- Gas-water system: $P_c = P_g - P_w$

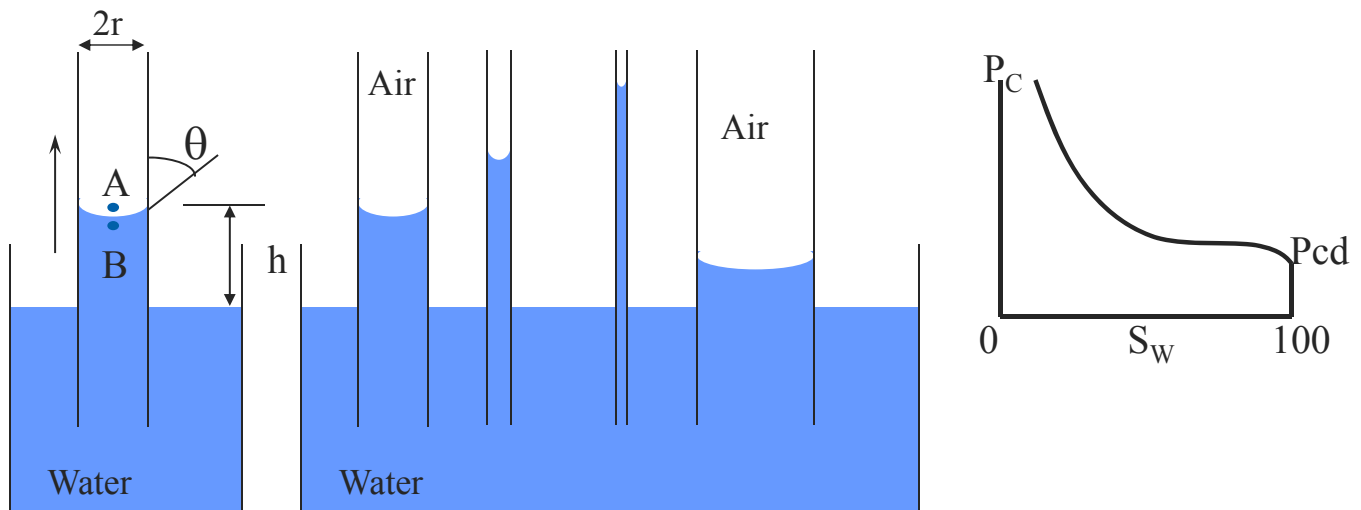
Capillary Pressure

Capillary Pressure in porous media

► Modeling the porous media as a bundle of capillary tubes of different radii

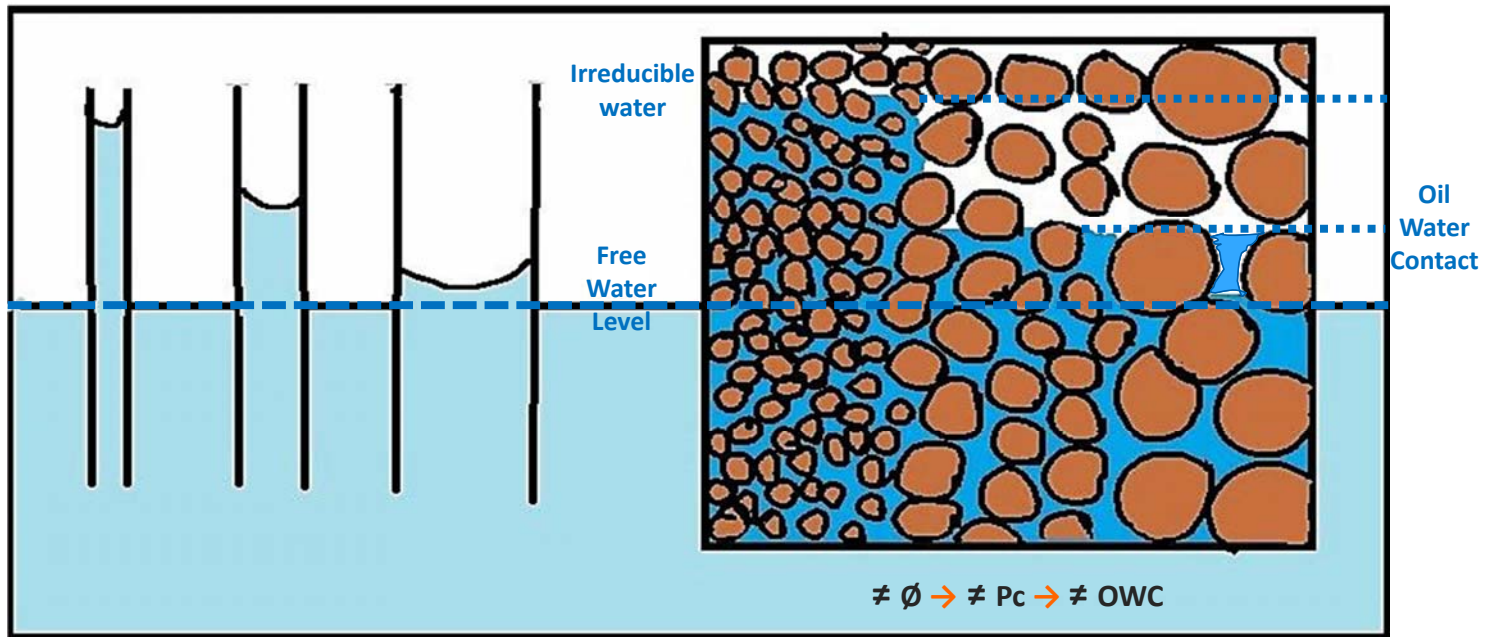
$$P_c = \frac{2\sigma \cos \theta}{r}$$

- for a fixed P_c we can calculate the corresponding radius r
- **Every pore whose radius is $< r$ is filled with the wetting phase** (typically water)
- The variation of P_c as a function of S_w defines the **Capillary Pressure curve**



Capillary Pressure

Capillary Pressure and fluid distribution

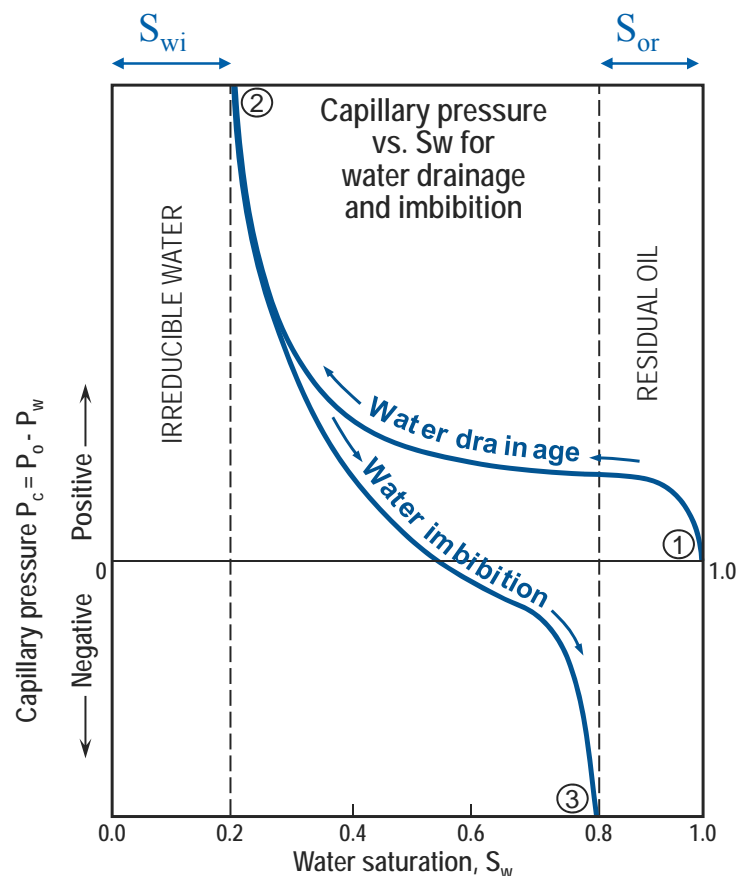


Capillary Pressure

Capillary Pressure curve

► The Capillary Pressure curve defines the relationship between P_c and S_w

- Obtained from laboratory experiments on core samples
- If the test is performed with a non-wetting fluid (oil) displacing a wetting fluid (water), it is called a **drainage** capillary pressure curve.
- If the test is performed with a wetting fluid (water) displacing a non-wetting fluid (oil), it is called an **imbibition** capillary pressure curve.
- Some remarkable points:
 - P_{cd} **displacement capillary pressure**
 - S_{or} **residual oil saturation**
 - S_{wi} **irreducible water saturation**



Capillary Pressure

Drainage and imbibition in the reservoir

► Drainage: the non-wetting phase is displacing the wetting phase

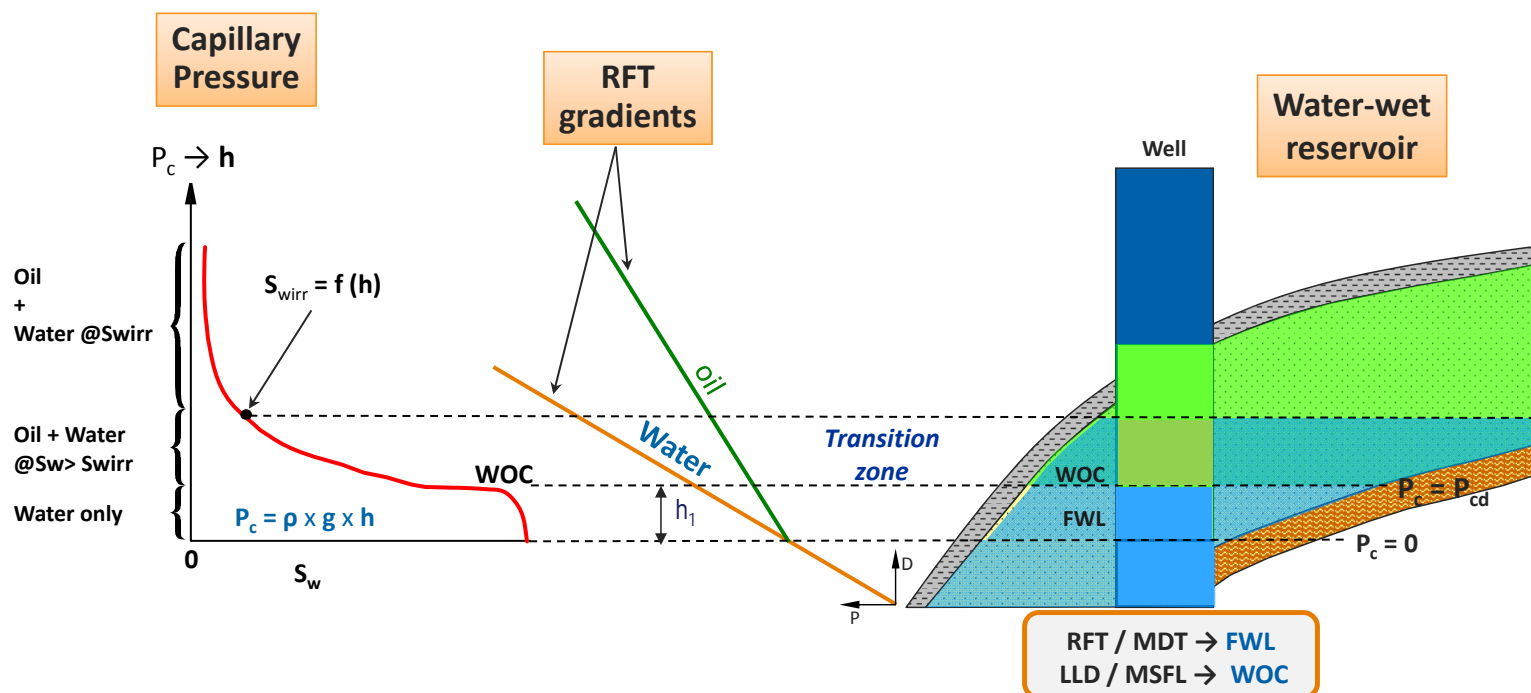
- Water-oil system
 - Oil is displacing water: hydrocarbons put in place in a classical water-wet reservoir
- Gas-liquid (water or oil) system
 - Gas is displacing oil: gas injection or gas cap expansion
 - Gas is displacing water: gas storage

► Imbibition: the wetting phase is displacing the non-wetting phase

- Gas-liquid system
 - Water is displacing gas : typically a gas reservoir under invasion of water from an active aquifer
- Water-oil system
 - Spontaneous imbibition: $P_c > 0$, water is displacing oil in water-wet pores
 - Forced imbibition: $P_c < 0$, water is displacing oil, porous medium is oil-wet

Capillary Pressure

Capillary Pressure and fluid distribution in the reservoir



FWL = Free Water Level → $P_c = 0$

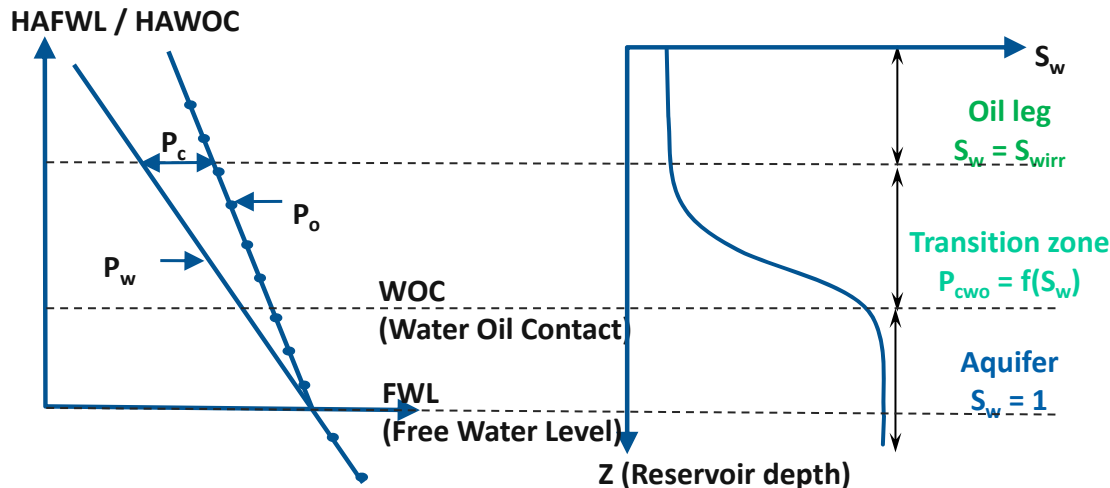
WOC = Water-Oil Contact → $S_w = 1$ corresponding to displacement pressure $P_{cd} = \Delta \rho \cdot g \cdot h_1$

Capillary Pressure

Initial saturation – height function

► Calculating initial fluid distribution in the reservoir

- If the origin is taken at FWL
 - Defining HAFWL = Height Above FWL: $HAFWL = FWL - Z$
 - $P_c = \Delta\rho \cdot g \cdot HAFWL$ and $P_c(S_w)$ from lab experiments $\Rightarrow HAFWL(S_w)$
- If the origin is taken at the WOC
 - Defining HAWOC = Height Above WOC: $HAWOC = WOC - Z$
 - $P_c - P_{cd} = \Delta\rho \cdot g \cdot HAWOC$ and $P_c(S_w)$ and P_{cd} from lab experiments $\Rightarrow HAWOC(S_w)$



Capillary Pressure

Conversion from laboratory to reservoir

► Generally, $P_c(S_w)$ is obtained in laboratory at ambient conditions with model fluids \Rightarrow a correction is needed to get $P_c(S_w)$ representative of the reservoir conditions

- From Laplace's formula

$$P_c = \frac{2\sigma \cos \theta}{r}$$

- Assuming radius r is identical between lab and reservoir conditions \Rightarrow same porous medium and no alteration from reservoir to laboratory we get:

$$P_c^{res} = P_c^{labo} \frac{\sigma^{res} \cos \theta^{res}}{\sigma^{lab} \cos \theta^{lab}}$$

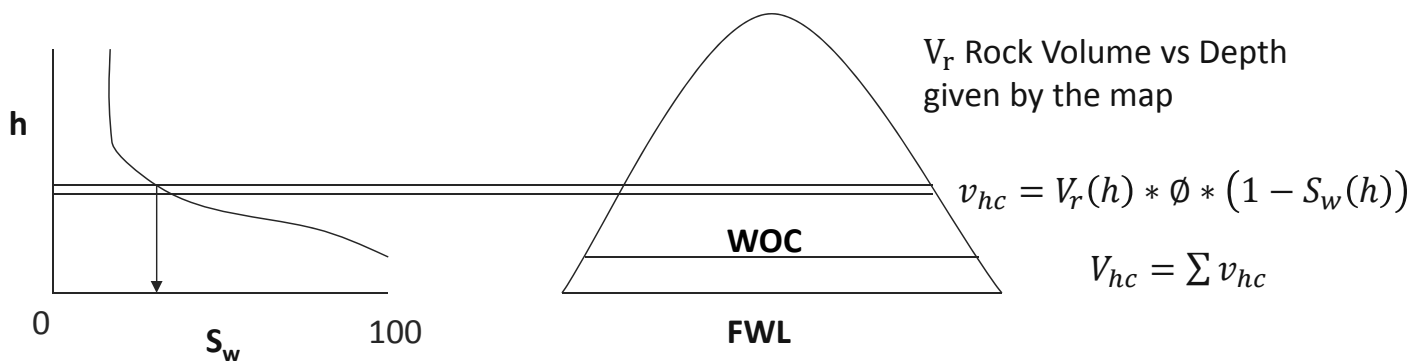
- The formula may be further simplified assuming the contact angle θ is identical between laboratory and reservoir conditions i.e. assuming the wettability conditions are identical
- The interfacial tension σ has to be corrected as soon as model fluids are used

Capillary Pressure

Accumulation from Capillary Pressure curve

► Method:

- $P_c(S_w)$ obtained at the laboratory
- Conversion to reservoir conditions
- Then either
$$P_c(h) = \Delta\rho \cdot g \cdot H$$
from the zero capillary pressure depth FWL
- Or
$$P_c(h) - P_{cd} = \Delta\rho \cdot g \cdot h$$
from the zero oil saturation depth WOC
- From $P_c(S_w)$ and $P_c(h) \Rightarrow S_w = f(h) \Rightarrow$ accumulation by integration of volumes
- WOC may be confirmed from logs



Capillary Pressure

Irreducible water saturation from P_c curve

- In theory, the irreducible water saturation corresponds to the vertical asymptote of the $P_c(S_w)$ curve
- Actually, S_{wirr} is difficult to determine since experience shows that vertical asymptotes are rarely observed
 - It should be more correct to speak about S_w for a given maximum value of P_c
 - Restored type measures are recommended (included SCAL) together with Purcell/centrifuge measurements (cf. below) in order to get reliable conclusions
 - Conventional measurements can only rank the samples

Methods for measuring Capillary Pressure

► Porous plate method

- Ambient or reservoir conditions (P,T)
- Model or reservoir fluids

► Centrifuge method

- Ambient conditions
- Model fluids

► Mercury Injection method (MICP)

- Together with pore size distribution (mercury porosimetry)

► Commonly used fluid systems

- Air-brine / Air-oil
- Water-oil
- Specific reservoir fluids

Capillary Pressure

Porous plate method - 1

► Principle:

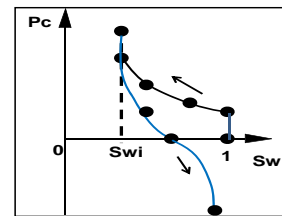
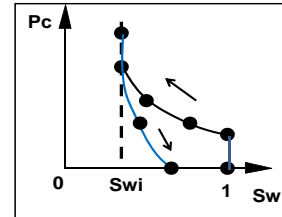
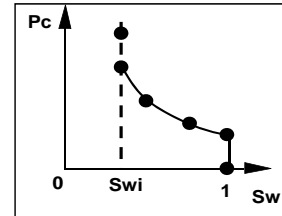
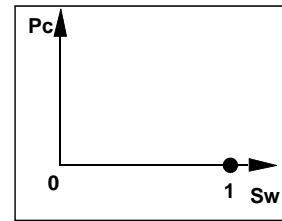
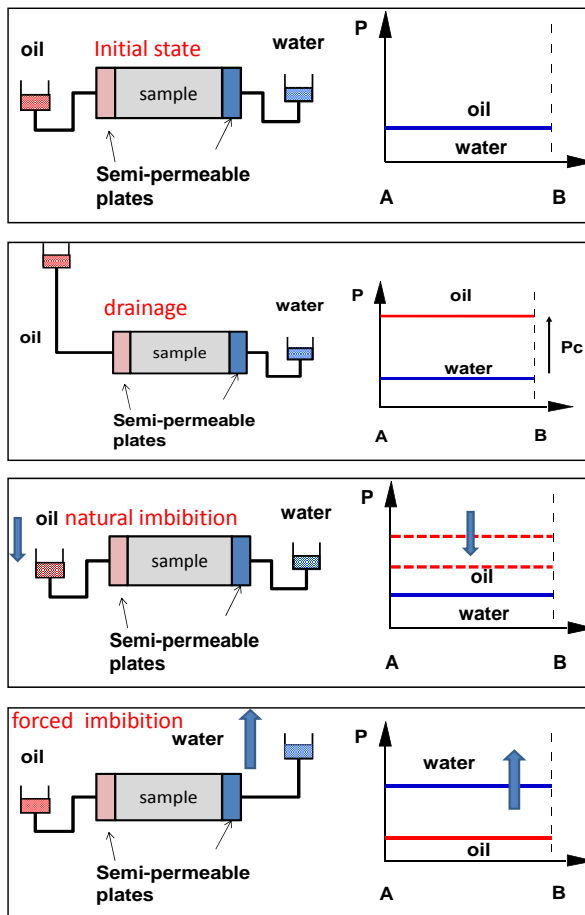
- Displacement of wetting fluid by non-wetting fluid by increasing the pressure step by step
 - => Drainage curve
 - => Determination of displacement pressure (when non-wetting phase begins to enter)
 - => Determination of irreducible saturation (when production of wetting phase stops)
- Displacement of non-wetting fluid by wetting fluid by decreasing the pressure step by step
 - => Imbibition curve
 - => Determination of residual saturation (when production of non-wetting phase stops)
- Pressure is measured directly; saturation is deduced from the volumes of fluids injected

► Remarks

- Wettability effect needs to be addressed => working on restored sample
- Representative (as real fluids are used)
- May be long (several months)

Capillary Pressure

Porous plate method - 2



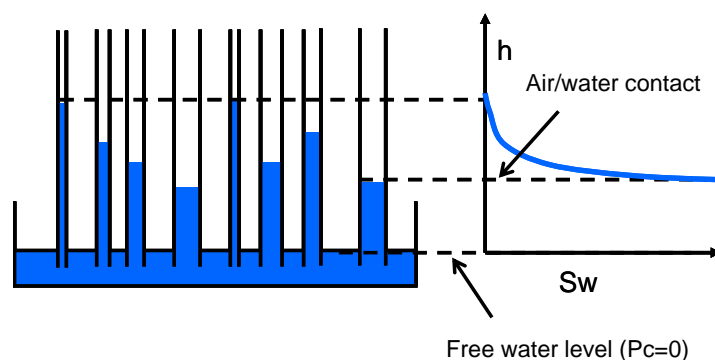
Reservoir rock properties - Saturation - Capillary pressure - Wettability

Capillary Pressure

Centrifuge method - 1

► Principle

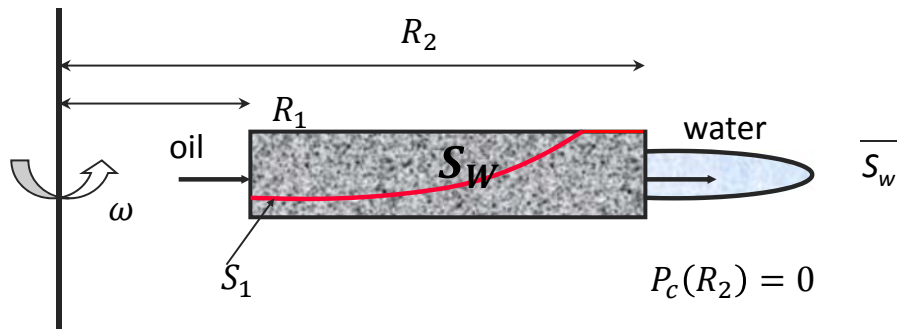
- Gravity drainage (see transition zones)
=> P_c could be derived from saturation profile during a gravity drainage
- $$P_c = \Delta \rho \cdot g \cdot h$$
- But required samples of 100 m long!
 - As $\Delta \rho$ cannot be modified, g is increased in order to get the same value of the product $g \cdot h$



Reservoir rock properties - Saturation - Capillary pressure - Wettability

Capillary Pressure

Centrifuge method - 2



► We get

$$P_c(R_1) = \Delta\rho \frac{\omega^2}{2} (R_2^2 - R_1^2)$$

► Remarks

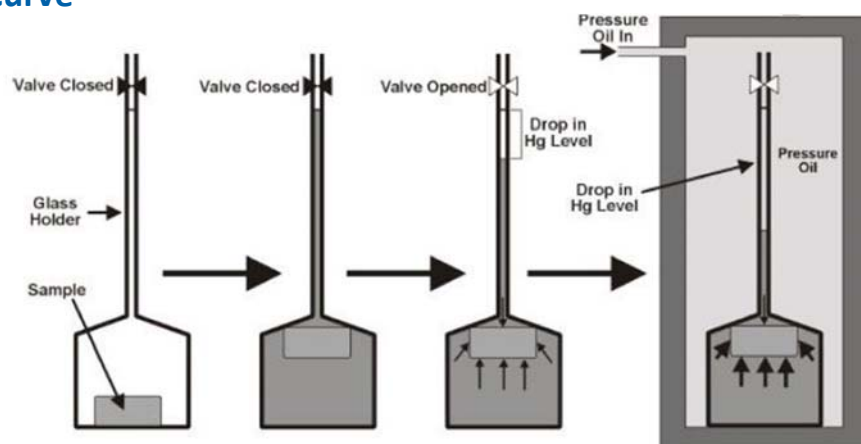
- Need some mathematical calculations for interpretation
- Because of wettability effect, S_{wirr} is only semi-representative (aged samples are used but model fluids are used instead of real fluids)
- Fast (1 day per step)
- High capillary pressure can be reached

Capillary Pressure

Mercury Injection MICP - 1

► Principle

- The sample is initially put in a pressure vessel under vacuum
- The vessel is filled with mercury (allowing to determine the bulk volume of the sample)
- The pressure is set to atmospheric pressure allowing mercury to enter the larger pores (volume of macropores) if any
- The pressure is increased step by step, allowing mercury to enter smaller and smaller pores => **drainage curve**
- The pressure is decreased step by step allowing mercury to exit larger and larger pores => **imbibition curve**



► Practical considerations

- Pressure is generally limited to 150-200 bars but can rise much higher
- Carried out on dried sample
 - Fluid-surface interactions are not allowed
- Correction needed to get reservoir capillary pressure
- They give access to other parameters of interest
 - Bulk volume
 - Pore volume
 - Pore size distribution: actually, for a given injection pressure (which is the capillary pressure), the volume of mercury injected is expressed as a percentage of the pore volume which is interpreted as the pore size distribution
 - They may allow to estimate permeability (see below)
- Fast but destructive

► Procedure

- A plug initially containing water is oil-flooded to irreducible water saturation $S_{wirr} = S_1$
- The plug is immersed in brine and spontaneous imbibition occurs leading to water saturation $S_w(@P_c = 0) = S_2$ and $\Delta S_{ws} = S_2 - S_1$
- The plug is placed in a flow cell and water is forced through leading to residual oil saturation $S_w = 1 - S_{or} = S_4$ and $\Delta S_{wt} = S_4 - S_1$
- The plug is immersed in oil and spontaneous oil imbibition occurs leading to water saturation $S_w(@P_c = 0) = S_3$ and $\Delta S_{os} = S_4 - S_3$
- Finally the plug is placed in a flow cell and oil is forced through leading to irreducible water saturation $S_{wirr} = S_1$ and $\Delta S_{ot} = S_4 - S_1$

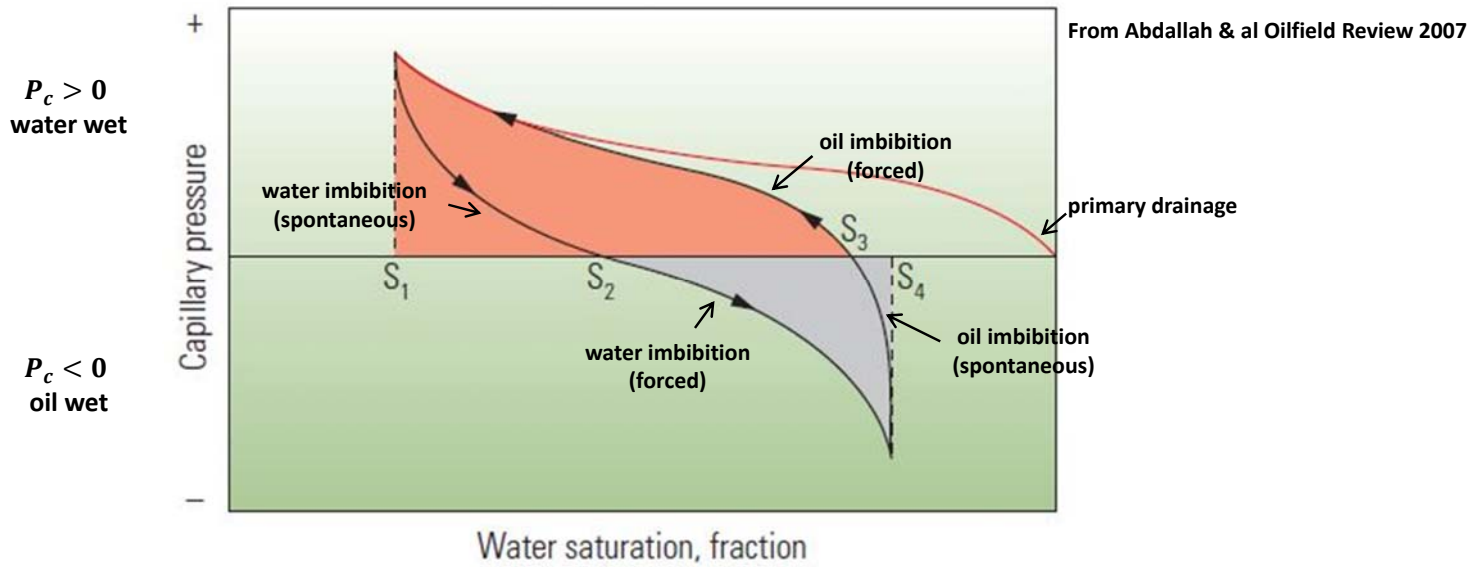
► Imbibition index

$$I_w = \frac{\Delta S_{ws}}{\Delta S_{wt}} \quad \text{and} \quad I_o = \frac{\Delta S_{os}}{\Delta S_{ot}}$$

$$\Rightarrow \text{Amott-Harvey index} = I_w - I_o$$

Capillary Pressure

Wettability from Amott-Harvey test - 2



$$I_w = \frac{\Delta S_{ws}}{\Delta S_{wt}} = \frac{S_2 - S_1}{S_4 - S_1} \quad \text{and} \quad I_o = \frac{\Delta S_{os}}{\Delta S_{ot}} = \frac{S_4 - S_3}{S_4 - S_1} \Rightarrow \text{Amott-Harvey index } WI = I_w - I_o$$

Capillary Pressure

Wettability from Amott-Harvey test - 3

► Wettability after Amott-Harvey test

- WI ranges between -1 and $+1$ with the following assessment

<u>Wettability</u>	<u>WI range</u>
Water-wet	+0.3 to 1.0
Slightly Water-Wet	+0.1 to +0.3
Neutral	-0.1 to 0.1
Slightly Oil-Wet	-0.3 to -0.1
Oil-Wet	-1.0 to -0.3

Wettability from USBM test - 1

► Procedure

- A plug is placed in a centrifuge and it is spun at stepwise-increasing speeds
- The plug is initially at irreducible water saturation $S_w = S_{wirr}$ in a water filled tube
- After several spin rates, the plug reaches the residual oil saturation S_{or}
- It is placed into an oil-filled tube for others measurements

► USBM index

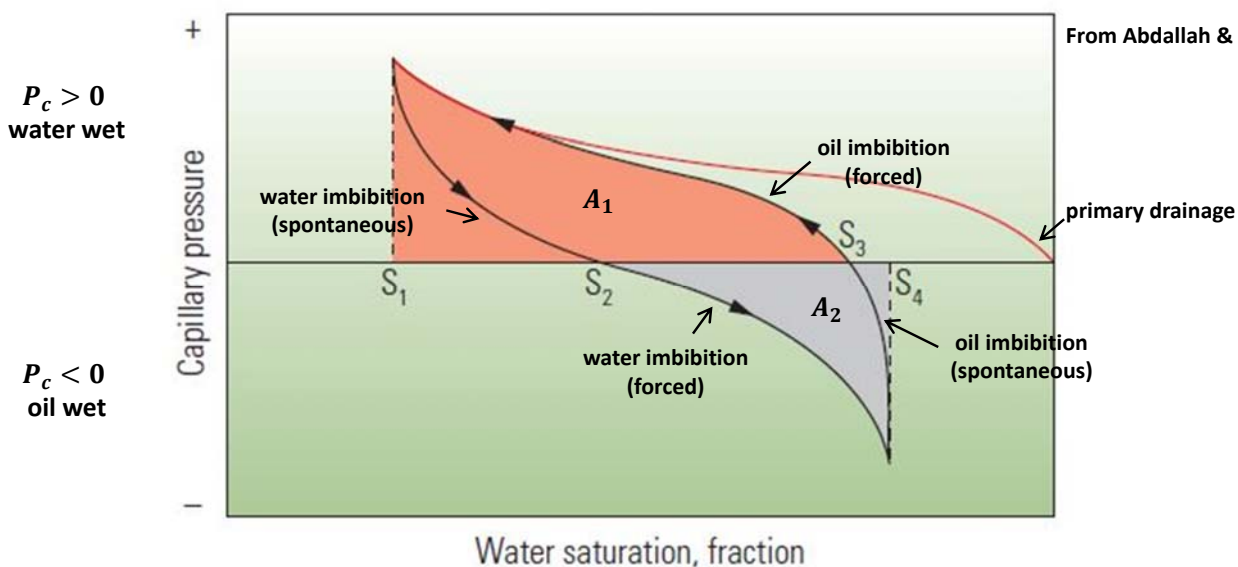
- The area A_1 and A_2 between each of the capillary-pressure curves and the zero capillary-pressure lines are calculated and

$$I_{USBM} = \log A_1/A_2$$

- The areas A_1 and A_2 represent the work (i.e. the energy to be provided) necessary for one fluid to displace the other

Capillary Pressure

Wettability from USBM test - 2



$$USBM \text{ index } I_{USBM} = \log A_1/A_2$$

Wettability from USBM test - 3

► Wettability after USBM test

- USBM index theoretically ranges from $-\infty$ (strongly oil-wet) to $+\infty$ (strongly water-wet) but typically ranges from -1 to $+1$
- **Negative values relate to oil-wet systems while positive values relate to water-wet systems**
- **The higher the absolute value, the stronger the effect**
- USBM test is more sensitive than Amott test near neutral wettability
- USBM test is fast because of centrifugation but it needs to correct the saturations (because of non-linear capillary pressure gradients within the sample due to the centrifuge)

► Combining Amott and USBM test

- It is possible to use centrifuge rather than flooding within water-filled and oil-filled cells in order to obtain the forced flooding states

Wettability from imbibition method

► The most commonly used qualitative method for determining wettability: imbibition

- It measures the rate and amount of oil expelled out of a core during an imbibition test in oil and water
 - Strongly water-wet: large and fast water imbibition
 - Weakly water-wet: small and slow water imbibition
 - Neutral wet: no water imbibition
 - Weakly oil wet: small and slow oil imbibition
 - Strongly oil-wet: large and fast oil imbibition
- Advantages: simple and fast
- Drawbacks
 - Not available for live fluids
 - Rough qualitative results
 - In addition to wettability, the result depends on viscosity, interfacial tension, pore structure, initial water saturation, ...

Capillary pressure modeling – Leverett function

► Leverett proposed to adimensionalize the capillary pressure curve

- J-function allows to remove discrepancies between $P_c(S_w)$ curves coming from various samples within one formation (and possibly to get one single $P_c(S_w)$ curve once the (k, Φ) couple of values is determined)
- J-function may also allow further modeling e.g. as a function of water saturation S_w

► Leverett function: reduced capillary pressure

$$J(S_w) = \frac{P_c}{\sigma \cos \theta} \sqrt{\frac{k}{\Phi}}$$

- Leverett classically interpreted $\sqrt{\frac{k}{\Phi}}$ as proportional to the mean pore radius

► Correlation with water saturation

$$J = a(S_w^*)^b$$

where $S_w^* = \frac{S_w - S_{wirr}}{1 - S_{wirr}}$ is the normalized water saturation and **a** and **b** are constants

One approach for using J-function

► J-function to determine fluid saturation distribution in the reservoir

- Porosity Φ known at the wells => interpolation through the reservoir
- Permeability **k** : from well testing or from (k, Φ) laws determined in the laboratory
- Saturation S_w : from $P_c(S_w)$ curve if reservoir is homogeneous or from $J(S_w)$ if it is not ; these curves are determined from laboratory experiments
- Either $P_c(S_w)$ directly
- Or $P_c(S_w) = J(S_w) \sigma \cos \theta \sqrt{\frac{\Phi}{k}}$
- Since $P_c = \Delta \rho g h \Rightarrow S_w(h)$



► Wettability

- A measurement of the tendency of one fluid to spread on the surface of a solid in presence of a second fluid
- A rock-fluid interaction property

► Wettability is characterized by a contact angle

- Wetting fluid: contact angle $\Theta < 90^\circ$
- Non-wetting fluid: contact angle $\Theta > 90^\circ$

► Wettability in the reservoir

- Measures the preference of the rock either to water or oil
- Has a strong influence on major reservoir characteristics (capillary pressure, fluid saturations, relative permeability) and finally on accumulation and reserves
- For long, most reservoirs were supposed to be water-wet; today, existence of mixed-wet or oil-wet reservoirs is widely recognized
- Influent parameters: oil composition, mineralogy, brine salinity, temperature

Interfacial Tension – Capillary Pressure



► Interfacial Tension IFT

- The surface energy existing between two immiscible fluid phases such as oil and water
- The greater the IFT, the less miscible the two fluids
- Oil-water is typically a non miscible system while oil-gas system may be miscible or non-miscible depending on the reservoir conditions

► Capillary Pressure

- The difference of pressure within the porous medium between the non-wetting fluid and the wetting fluid
- Pressure is always greater within the non-wetting fluid than within the wetting fluid
- Laplace equation: $P_c = \frac{2\sigma \cos \theta}{r} = P_{nw} - P_w$
- Capillary pressure depends on the wettability, the porous medium (through the pore diameter) and IFT



► Capillarity in the reservoir

- Porous media are modeled as a bundle of capillary tubes
- Gas is always the non-wetting phase, water is generally the wetting phase
- For gas/liquid systems
- $P_c = P_g - P_{liq}$
- Convention for oil/water system **regardless of wettability conditions**:
 - $P_c = P_o - P_w$
 - If $P_c > 0$ the system is water-wet
 - If $P_c < 0$ the system is oil-wet

► Capillary Pressure curve

- Curve $P_c(S_w)$ obtained through laboratory experiments on cores
- Given P_c , one can calculate a corresponding value of pore radius r : all pores of inferior radius are filled with wetting fluid, typically water
- From the curve, it is possible to determine P_{cd} (displacement cap. Pressure), S_{or} (residual oil saturation) and S_{wirr} (irreducible water saturation)



► Drainage: displacement of wetting fluid by non-wetting fluid

- Typically displacement of water by oil (or gas) at initial migration of hydrocarbons in place

► Imbibition: displacement of non-wetting fluid by wetting fluid

- Typically displacement of oil by water corresponding to production

► Fluids in place in the reservoir:

- The Free Water Level is defined by $P_c = 0$
- The Water Oil Contact is defined by $S_w = 1$
- The difference between FWL and WOC is due to the displacement capillary pressure P_{cd}
- In water-wet reservoirs, WOC is above FWL, i.e. FWL is in the water zone, and there is a transition zone where S_w decreases from 1 to S_{wi}
- In oil-wet reservoirs, WOC is below FWL, i.e. FWL is in the oil zone; oil saturation is at its maximum at the bottom of the reservoir but may decrease above



- ▶ Initial fluid distribution in a reservoir depends on the balance between capillary pressure and gravity forces
- ▶ Accumulations from Capillary Pressure curve
 - From $P_c - P_{cd} = \Delta\rho \cdot g \cdot h \Rightarrow P_c(h)$
 - From laboratory and after conversion to reservoir conditions $\Rightarrow P_c(S_w)$
 - From $P_c(h)$ and $P_c(S_w) \Rightarrow S_w = f(h)$ thus allowing to calculate accumulations
- ▶ Capillary Pressure has also a strong influence on the fluid production
- ▶ Capillary pressure may be adimensionalized using J-function

Permeability

Permeability

Notion of viscosity

- ▶ **Viscosity: ability of a fluid to flow**
- ▶ **Depending of the type of the fluid**
 - Gas viscosity \ll oil viscosity
 - Gas viscosity: 0.01 cP – Water viscosity: 1 cP (@std conditions)
 - Orinoco oil: 5 000 cP – Athabasca oil: 1 000 000 cP !!!

Oil	Light	Medium	Heavy
Density	0.75 to 0.82	0.83 to 0.92	0.93 to 1
FVF (rm^3/m^3)	3 to 2	1.5	1.1 to 1
R_s (m^3/m^3)	300 to 200	100	10 to 0
Viscosity	<1 cP	1-20 cP	> 100cP

Permeability

Definition of viscosity

- Poiseuille flow of a viscous fluid with $V(x) = \text{cte}$ and $V(t) = \text{cte}$

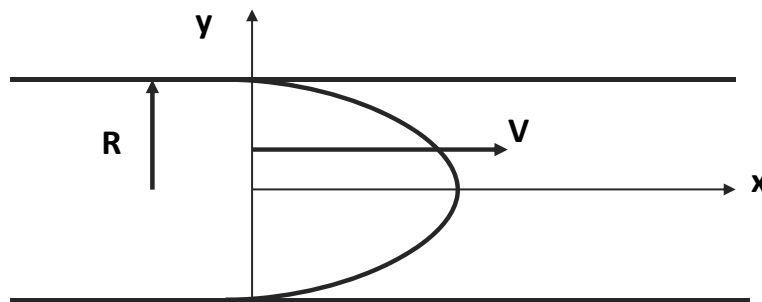
$$V_y = \frac{aR^2}{4\mu} \left(1 - \frac{y^2}{R^2}\right)$$

$$V_{\max} = \frac{aR^2}{4\mu}$$

$$\tau = \mu \frac{dV}{dy}$$

τ is the shear stress (friction force)

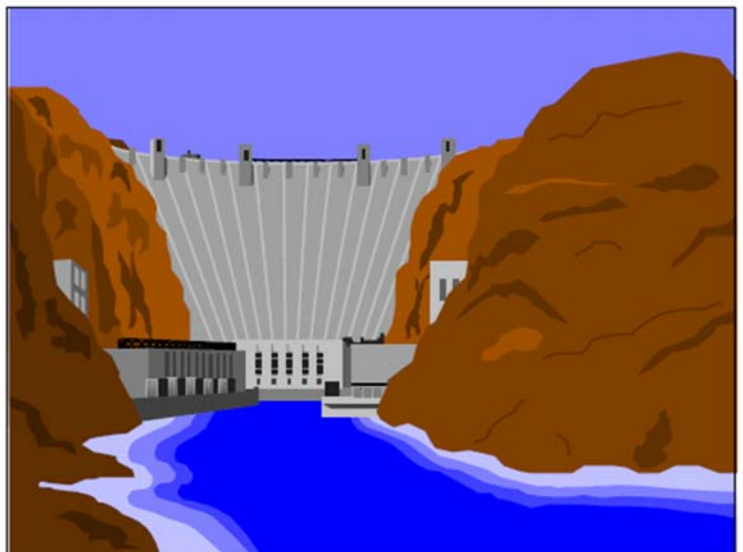
μ is the viscosity



Permeability

Flow in a porous media

- A driving force gradient is required for a fluid flow between two points.
 - Ex: gravity forces
- Porous medium is a resistance against flow



Permeability

Darcy's experiment in 1856

- Sand saturated with water

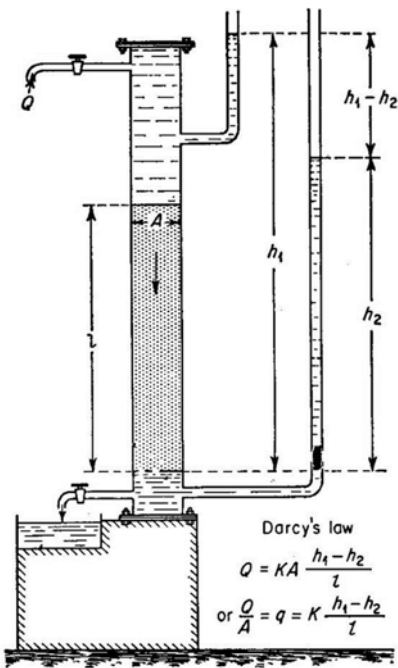
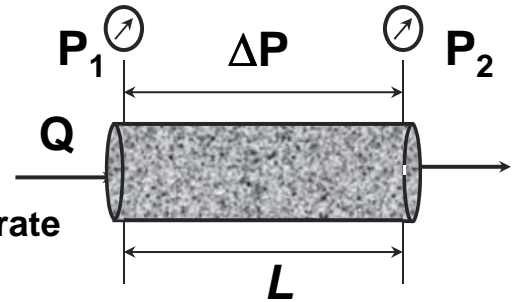
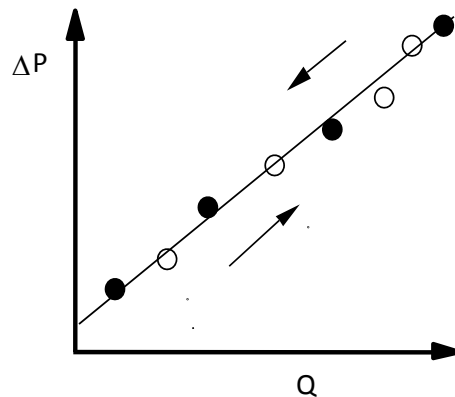


FIG. 2-26. Schematic drawing of Henry Darcy's experiment on flow of water through sand. (From Hubbert.²²)



Permeability

Darcy's law for linear flow

- **Permeability:** a measure of the **ability of the porous media to transmit fluids**
- **Darcy's Law:**

$$Q = \frac{k}{\mu} A \frac{P_1 - P_2}{L}$$

Q : injection flow rate (cm^3/s)

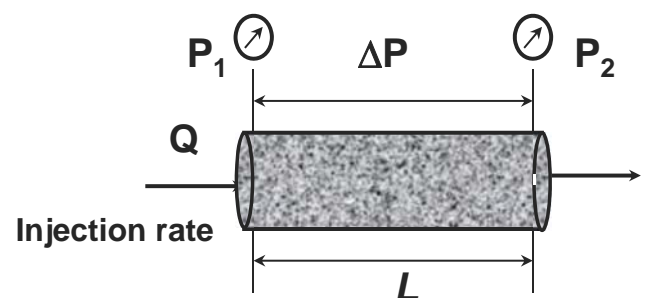
L : length (cm)

A : cross sectional area (cm^2)

ΔP : differential pressure (atm)

μ : fluid viscosity (cP)

k : permeability (Darcy)



- **Unit: k in Darcy**

- Homogeneous to a surface: $1 \text{ Darcy} = 0.987 \times 10^{-12} \text{ m}^2$
- Typically: 0.1 mD (lower limit for conventional reservoirs) $< k < \text{several Darcy}$ (fractures)

- **This equation is used for describing linear flow within plugs in laboratory**

Permeability

Darcy's law for radial Flow

► After integrating

$$Q = \frac{2\pi h k}{\mu} \frac{P_1 - P_2}{\ln \frac{r_1}{r_2}}$$

Q: flow rate (cm³/s)

r₁: drainage radius (cm)

r₂: well radius (cm)

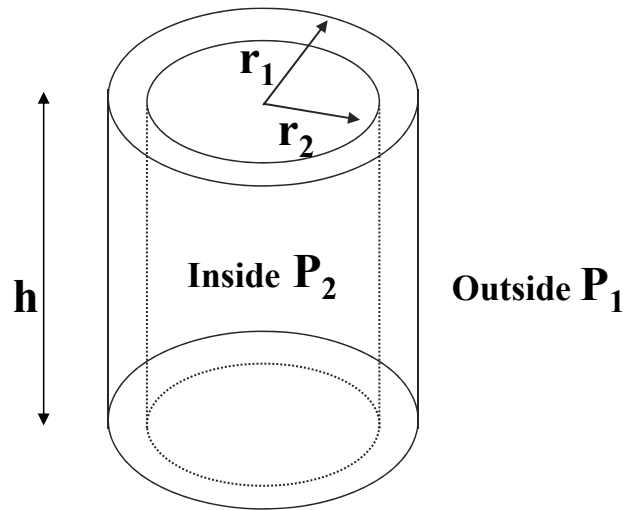
P₁: reservoir pressure (atm)

P₂: well flowing pressure (atm)

h: thickness (cm)

μ: viscosity (cP)

k: permeability (Darcy)



► This equation is valid to describe radial flow in the reservoir near the wellbore

Permeability

General Darcy's law for gas

► General Darcy's law:

- For liquids and gas at low speed, previous expression of Darcy's law is valid
- At high speed, flow is no longer laminar and inertial effects cannot be neglected => there is a deviation and an additional term is introduced to take it into account

$$dP = \frac{\mu Q_m}{Ak\rho} \left(1 + \frac{u Q_m}{\mu A} \right) dx$$

Where

ρ is the fluid density

Q_m is the mass flow rate

u is the shape parameter of the pores

► For gas:

- Darcy's law for axial flow: $Q = \frac{k}{\mu} A \frac{P_1^2 - P_2^2}{2LP}$
- Darcy's law for radial flow: $Q = \frac{2\pi h k}{\mu} \frac{P_1^2 - P_2^2}{2P \ln \frac{r_1}{r_2}}$

Measurement of permeability

► Principle:

- Permeability is a **property of the porous medium only** reflecting its internal structure (porous network especially pore throats) and can be measured using **any** fluid
- Usually, permeability is measured using gas, especially air (since it will flow faster and therefore reduce the duration of the experiment) $\Rightarrow k_g$
- Sometimes using water $\Rightarrow k_w$
- Plug: diameter = 23 mm (possibly 40 mm) $L = 23$ mm

► Possible cause of errors

- Fissures (k abnormally high)
- Interactions fluid-rock (especially in the case of water – take care to salt composition)

► Correction

- Stress effect: in the case of unconsolidated formation
- **Klinkenberg correction** due to gas slippage $k_{gcorr} < k_{gmes}$
- Measured permeability is monophasic k_g or $k_w > k_o(S_{wi})$ in the reservoir (see below)

Permeability

Slippage effect & Klinkenberg correction - 1

► Definition

- Variation of permeability to gas with pressure

► Origin

- At low pressure, the mean free path of gas molecules increases and becomes of the same order of magnitude than the pore size \Rightarrow there are fewer and fewer collisions between gas molecules, what leads to a **slippage** of the gas molecules on the pore walls and a wall velocity that is not nil (unlike for laminar liquid flows)
- As a consequence, the measured permeability **overestimates** the « true » monophasic permeability and has to be corrected
- Klinkenberg proposed the equation

$$k_{gas} = k_L \left(1 + \frac{a}{P_m} \right)$$

where $P_m = (P_1 + P_2)/2$ is the mean flowing pressure

and a is the **slip factor**, a constant depending on the gas & porous medium

k_L is the **Klinkenberg permeability** and does **not** depend on the gas

- Klinkenberg permeability is an estimate of the value of the monophasic permeability that would have been measured using a liquid

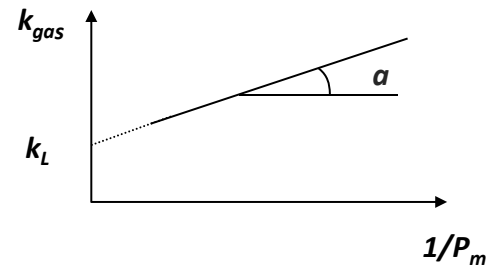
Permeability

Slippage effect & Klinkenberg correction - 2

► Klinkenberg correction

- Perform several experiments at various flow rates and pressure
- Plot measured permeability against reciprocal of pressure and extrapolate to infinity to get the “true” monophasic permeability

$$\frac{2Q\mu L}{A} \cdot \frac{P}{P_1^2 - P_2^2} = k_{gas} = k_L \left(1 + \frac{a}{P_m} \right)$$



- Remarks:
 - From the previous equation, the slippage effect can be neglected at high pressure ; indeed the gas behavior becomes closer to a liquid behavior when pressure increases;
 - At very low pressure, the flow reduces to molecular diffusion
 - Expected correction is high for low values of permeability (<1%) and low for high values of k (>50%)
 - Practice shows that k_L is rather an optimistic estimate of “true” reservoir permeability

Permeability

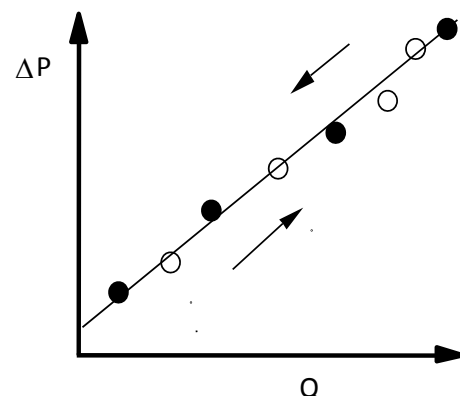
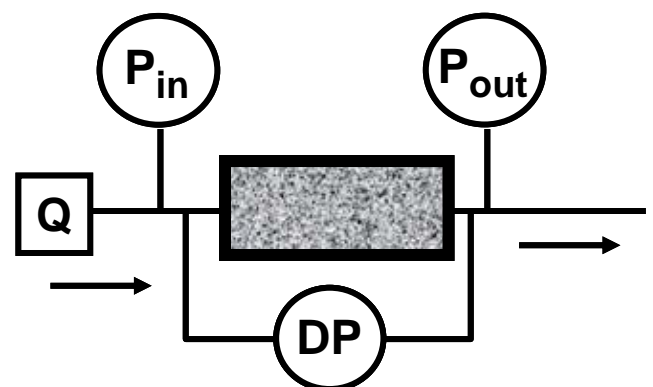
Measurement – Steady-state liquid flow

► Equation for a sample under a linear liquid steady-state flow

$$Q = \frac{-k}{\mu} A \cdot \frac{\Delta P}{L} = \frac{k}{\mu} A \cdot \frac{P_{in} - P_{out}}{L}$$

► Drawbacks

- May be long!
- Clay swelling



Permeability

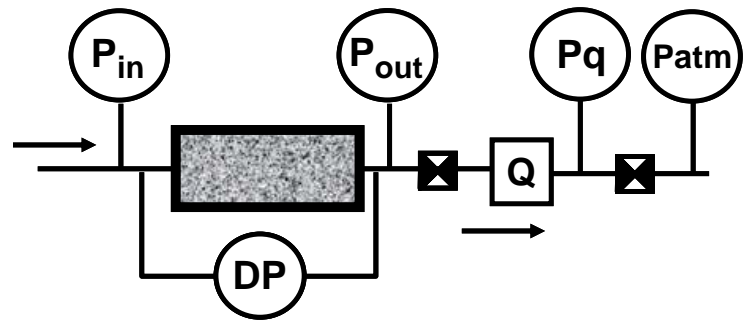
Measurement – Steady-state gas flow

- Equation for a sample under a linear gas flow:

$$\frac{Q}{A} = \frac{k}{\mu L} \frac{P_{in}^2 - P_{out}^2}{2P_q}$$

Where Q is the volume flow rate

And P_q is the pressure corresponding to the flow rate measurement



► Drawbacks

- Inertial effect in case of high speed
 - The flow is no longer laminar and Darcy's law does not apply
- Klinkenberg effect

Permeability

Measurement – Transient gas

► Principle

- We apply a small ΔP and from Darcy's law:

$$Q(t) = A \frac{k}{\mu} \frac{P(t) - P_0}{L}$$

- Considering a perfect gas:

$$PdV = RTdn \quad \text{and} \quad Q = dV/dt$$

$$\text{Hence } Q(t) = \frac{RT}{P} \frac{dn}{dt}$$

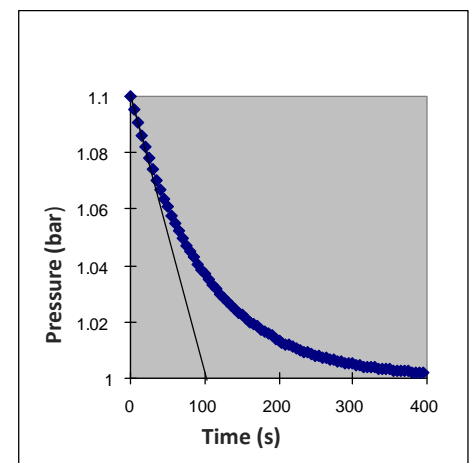
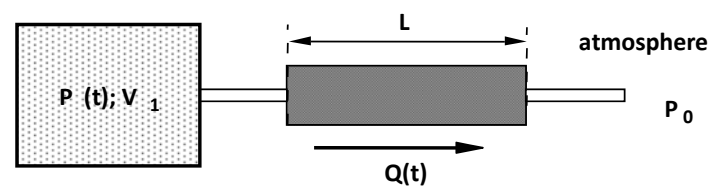
- In the vessel $dP \cdot V_1 = -RTdn$

$$\text{Hence } \frac{dP}{P - P_0} = \frac{-AkP}{\mu LV_1} dt$$

- Considering that $P_1 - P_0 \ll P_0$ we get:

$$P - P_0 = (P_1 - P_0) \exp(-t/\tau)$$

where τ is the relaxation time: $\tau = \frac{\mu LV_1}{AkP_0} \Rightarrow k$ from τ



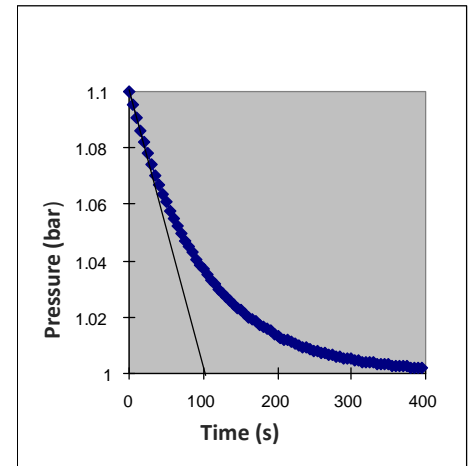
Measurement – Transient gas - 2

► Advantages

- Better accuracy (no flow rate measurement)
- Less equipment
- Large range of measurement with different vessels

► Drawbacks

- Numerical calculations in the general case



V_1 = 1 liter
 L = 10 cm
 A = 10 cm²
 P_0 = 1 bar
 P_1 = 1.1 bar
 $\mu(\text{air})$ = 10⁻² cP
relaxation time = 100s
 k = ?

Measurement of very low permeabilities ($k < 1 \mu\text{D}$)

► Experimental difficulties

- Leaks between the sample and rubber sleeve
- Surface fractures during plugging
- Microfractures
- Need for confining pressure (shales)
- Long equilibrium times (several days)

► Experimental procedures

- Small plugs or pieces of rocks (embedded in resin)
- Transients method based on the accumulation of gas for discrimination between fracture and matrix flow
- Interpretation by numerical simulations, check of equilibrium times

Estimation from MICP

► Swanson's equation

- From the MICP curve, determine the maximum ratio of mercury saturation to the corresponding capillary pressure $(S_b/P_c)_{max}$ and, from linear regression,

$$k = a(S_b/P_c)_{max}^c$$

where a and c are constants depending on the type of rock (sandstones vs. carbonates) and the fluid system (typically mercury-air)

- Swanson's regression is based on data from 203 sandstones samples and 116 carbonates samples ; combined sandstones and carbonates data give $c=2.005$

► Winland's equation

- From the correlation on permeability, porosity and capillary pressure, the empirical Winland's regression is

$$\log r_{35} = 0,732 + 0,588 \log k - 0.8641 \log \phi$$

where r_{35} is the pore throat radius at 35% mercury saturation (derived from the capillary pressure curve)

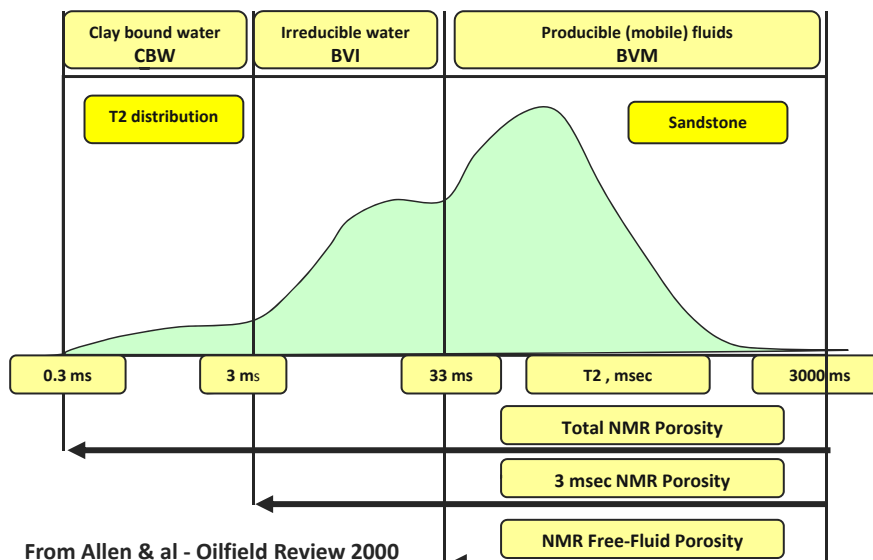
- Winland's regression is based on data from 312 samples

Permeability

Permeability from NMR measurements - Principle

► Principle

- NMR measurements provide information about total porosity through the distribution of the pore size
- Permeability is depending on the pore throat size
- It is possible to correlate permeability to the pore size and to the ratio surface/volume of the pore S/V



From Allen & al - Oilfield Review 2000

Permeability from NMR measurements - Models

- ▶ Two correlations models are used
- ▶ Free-fluid model or Coates model or Timur-Coates model

$$k_{TIM} = C \cdot \phi^m \cdot (FFI/BVI)^n$$

where *FFI* and *BVI* are respectively Free Fluid Index and Bound Volume Index and *C* is a formation-dependent parameter and *m* and *n* are constants, generally $m = n = 2$

- ▶ Schlumberger-Doll-Research (SDR) or Mean- T_2 model

$$k_{SDR} = C \cdot \phi^m \cdot (T_{2LM})^n$$

where T_{2LM} is the logarithmic mean of relaxation times T_2 and *C* is a formation-dependent parameter e.g. 4 for sandstones and 0,1 for carbonates and *m* and *n* are constants, generally $m = n = 2$

Permeability from NMR measurements – Interest

- ▶ Main interest of permeability measurements from NMR
 - NMR may be used on the field through dedicated logs
 - NMR permeability logs may provide a profile of permeability along the well
- ▶ Principle
 - To determine permeability from NMR typically by calibrating the model on intervals on interest and by confronting the results to measurements obtained from core samples => if the values correlate, the NMR permeability log can be used
- ▶ Limitations
 - Both models assume a good correlation between porosity, pore size, pore-throat size and pore connectivity => the assumption is generally valid in clastic formation (e.g. sand/shale) but in carbonates or other lithologies the permeabilities may not be reliable
 - The free-fluid model may be used for water- and hydrocarbon-saturated samples (provided a correction in the presence of hydrocarbon)
 - The SDR model cannot be used for hydrocarbon-saturated samples

Permeability

Some values of permeability

► Sandstones

- Tight sands: $k < 1$ mD
- Sandstone (shaly to not shaly): 0.1 to 100 mD
- Sandstone with carbonate cement: 0.1 to 100 mD
- Clean sandstone: 10 to 5000 mD
- Unconsolidated sandstone: 50 to 20000 mD (function of grain size, sorting and % of fines)

► Carbonates

- Compact carbonate : $k < 1$ mD (dolomite and limestone)
- Vuggy dolomite: 1 to 200 mD
- Compact limestone (k matrix < 0.1 mD): production only due to fractures.

► Permeability is a **property of the rock only** and it reflects the structure of the porous network

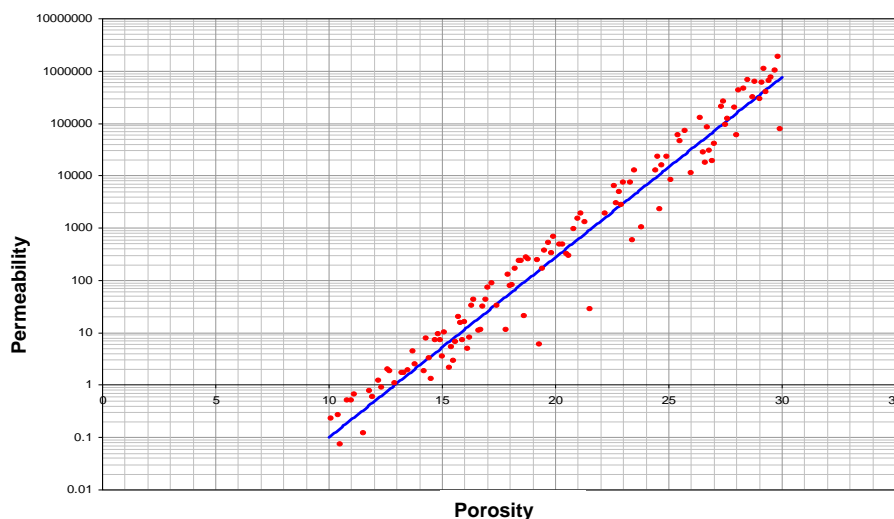
- Capacity of the porous network to let the fluid flow depending on the size of the pore throats

Permeability

Correlation k - ϕ

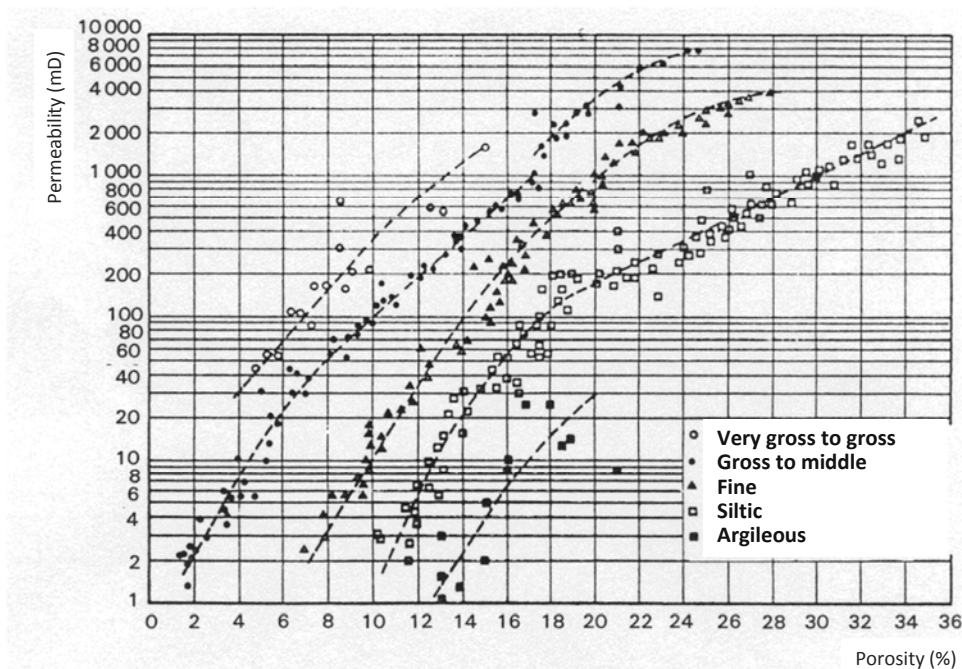
► Actually, depositional and environmental factors influencing porosity may also influence permeability => there is often a correlation between k and ϕ

- The relationship may vary with formation and rock-type but with the general trend of k increasing with ϕ increasing
- General relationship of the form $\log(k) = A \phi + B$
- k - ϕ correlation allows to define a **petrofacies** (together with a capillary pressure curve)



Permeability

k- ϕ correlation



Statistics made out of 610 samples of sandstones (source: Tiab & Donaldson 1996)

Influence of grain size on porosity-permeability correlation

Permeability

Mobility

► Mobility

$$M = \frac{k}{\mu}$$

► Mobility is a property of the rock (k) and of the fluid (μ):

- Mobility is a measure of the ability of a given fluid to flow in a given porous media
- Low viscosity fluids may still move in low permeability reservoirs
 - case of tight gas reservoirs $k < 0.1 \text{ md}$
- High viscosity fluids may still move in high permeability reservoirs

Mobility (mD/cP)	Assessment
1 - 10	Fair
10 - 100	Good
100 - 1000	Excellent

Consideration about flow regimes in the reservoir

- ▶ **Flow regimes are different in the near and far wellbore areas**

- ▶ **Near wellbore area (a few meters)**
 - Very large pressure gradients (10 to 100 bars/m)
 - Very high flow velocities (10 to 1000 m/d)
 - **Viscous forces prevail**

- ▶ **Far wellbore area (a few meters away from the well)**
 - Very small pressure gradients (0.05 to 0.005 bars/m)
 - Very low flow velocities (0.01 to 1 m/d)
 - **Viscous forces compete with gravity forces and capillary forces**

Darcy's law and flow in porous media

- ▶ **Two scales have to be taken into consideration**
 - porous network => **pore scale**
 - porous media => **reservoir scale**

- ▶ **Flow through porous network**
 - Microscopic pore scale => Navier-Stokes equations

- ▶ **Flow in porous media**
 - Large range of scales (from mm to km) => average of the flow at pore scale => Darcy's law = macroscopic flow equations

- ▶ **Darcy's law**
 - It correctly describes the single phase flow at **low velocity** in porous media at macroscopic scale
 - **It does not describe the flow at the pore scale**
 - It is used for reservoir simulation (especially for multiphase flow...)



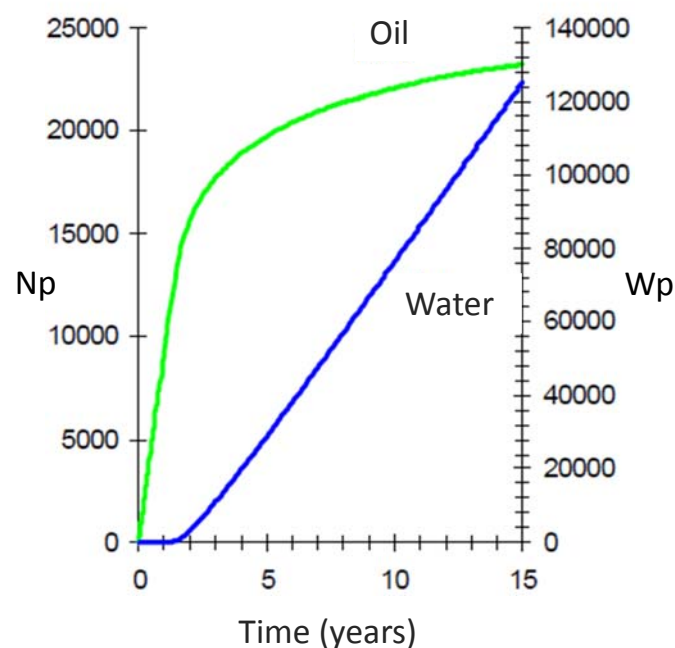
- ▶ **Permeability** is a measurement of the porous medium ability to let a fluid flow
- ▶ Permeability is a property of **porous media only**
- ▶ **Darcy's law** describes the movement of fluid within porous media at **macroscopic scale**
 - Axial flow for liquids: $Q = \frac{k}{\mu} A \frac{P_1 - P_2}{L}$ for gas: $Q = \frac{k}{\mu} A \frac{P_1^2 - P_2^2}{2LP_2}$
 - Radial flow for liquids: $Q = \frac{2\pi hk}{\mu} \frac{P_1 - P_2}{\ln \frac{r_1}{r_2}}$ for gas: $Q = \frac{2\pi hk}{\mu} \frac{P_1^2 - P_2^2}{2P_2 \ln \frac{r_1}{r_2}}$
- ▶ Permeability ranges from less than 0.1mD (tight sands or compact carbonates) up to several Darcy (unconsolidated sandstones or fractures)
- ▶ **Viscosity μ** is a measurement of the ability of a fluid to flow
- ▶ **Mobility k/μ** is a measurement of the ability of a given fluid to flow in a given porous medium

Relative permeability

Relative permeability

Multiphase flow – Why?

- ▶ Most of the oil or gas recovery is achieved while multiphase flow occurs in the reservoir
- ▶ Two or three fluids are frequently produced simultaneously at surface and are usually simultaneously mobile in the reservoir
 - **multiphase flow in porous media**
 - Production rate of each of these fluids varies with time:
 - How can we forecast production rate versus time?



Relative permeability

Darcy's law for multiphase flow

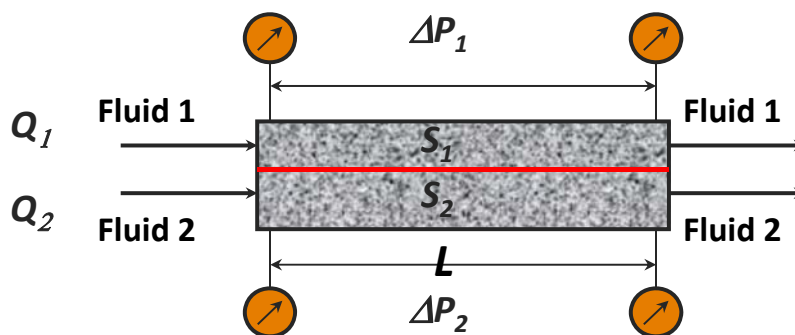
- ▶ The previous Darcy's law is valid for **monophasic** flow only and it needs to be extended to take the reservoir multiphase flows into account

- ▶ **Case of diphasic flow**

- Two fluids flowing in the porous medium
- The monophasic Darcy's law is extended by introducing the **effective permeability** that takes the presence of the other fluid in the porous medium into account

$$Q_1 = \frac{k_1}{\mu} A \frac{dP_1}{dx} \quad \text{where } k_1 \text{ is the effective permeability of fluid 1 by respect to fluid 2}$$

$$Q_2 = \frac{k_2}{\mu} A \frac{dP_{2w}}{dx} \quad \text{where } k_2 \text{ is the effective permeability of fluid 2 by respect to fluid 1}$$



Relative permeability

Definition of relative permeability

- ▶ From the previous extended Darcy's law for multiphase flow

$$Q_1 = \frac{kk_{r1}}{\mu} A \frac{dP_1}{dx}$$

$$Q_2 = \frac{kk_{r2}}{\mu} A \frac{dP_{2w}}{dx}$$

where k_{r1} is the relative permeability of fluid 1 by respect to fluid 2 (adimensional)

k_{r2} is the relative permeability of fluid 2 by respect of fluid 1 (adimensional)

k is the monophasic permeability (Darcy)

- ▶ Obviously, we get

$$k_{r1} = k_1/k$$

$$k_{r2} = k_2/k$$

- ▶ Effective and relative permeabilities are functions of the fluid saturations

$$k_{r1} = k_{r1}(S_1)$$

$$k_{r2} = k_{r2}(S_2)$$

Definitions

► Absolute permeability

- Permeability of a rock saturated completely with one fluid: k_{air} , k_{swi}

► Effective permeability

- Permeability of a rock to one fluid when the rock is only partially saturated with that fluid: $k_o(S_w)$, $k_w(S_w)$
- The effective permeability is the measure of the ability of the porous media to conduct one fluid in presence of the other ones

► Relative permeability

- Ratio of effective permeability to absolute permeability

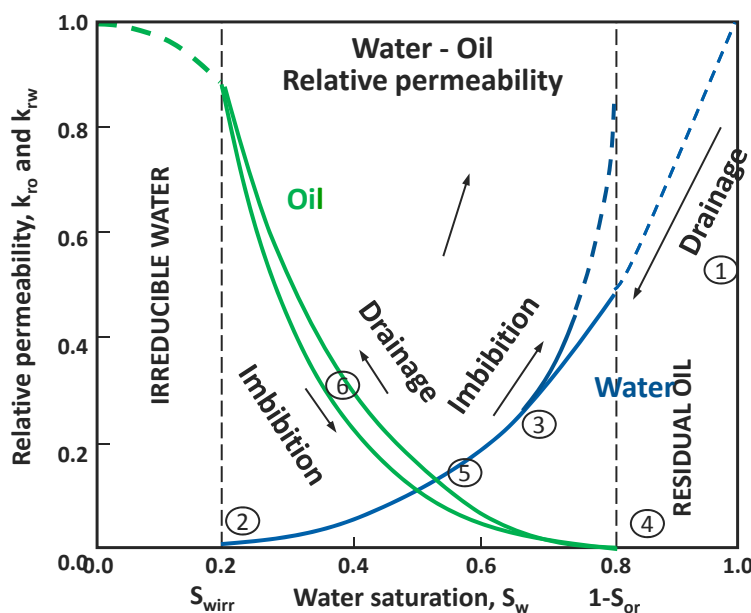
$$k_{ro} = \frac{k_o(S_w)}{k}$$

$$k_{rw} = \frac{k_w(S_w)}{k}$$

$$k_{rg} = \frac{k_g(S_w)}{k}$$

Relative permeability

Relative permeability curves - Oil/water system



- S_w is decreasing => drainage (corresponding to initial flooding of oil in the reservoir supposed initially water-wet)
- S_{wirr} irreducible water saturation : only oil moves $k_{ro}=0.8$ & $k_{rw}=0$
- S_w increases => imbibition (corresponding to oil production)
- S_{or} residual oil saturation : only water moves, oil is immobile
- crossing point : $k_{ro}=k_{rw}$ and $k_{ro}+k_{rw} < 1$
- hysteresis : not the same curve for imbibition and drainage due to the difference in invasion process between the wetting fluid and the non-wetting fluid (effect of capillary pressure); hysteresis is generally more marked for the non-wetting fluid

- Except for end points, the sum of relative permeabilities is always < 1 => each fluid disturbs the flow of the other one
- k_r curves **dictate the flow of fluids** in the reservoir and are used for reservoir simulation

Determination of relative permeability curves

- ▶ **Laboratory measurements are currently the only available method to estimate relative permeability**
- ▶ **No field measurements available yet**
- ▶ **The estimate of relative permeability from pore network modeling is still in the field of the research**
- ▶ **Method**
 - Reproduce a diphasic flow in a reservoir core
 - Mimic reservoir conditions (or simpler if acceptable)
 - Record production, pressure, differential pressure, composition vs time and in-situ saturations vs time and distance (scan)
 - Determine the
 - relative permeability

Parameters influencing the relative permeabilities

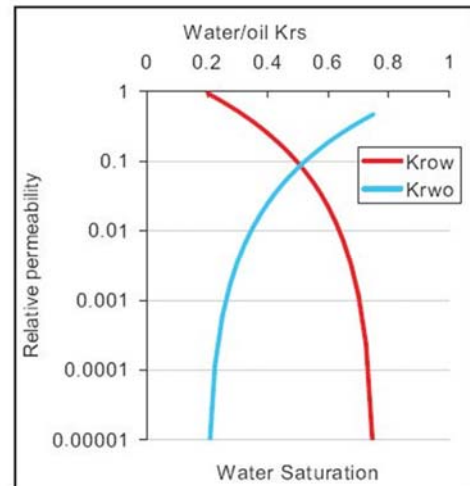
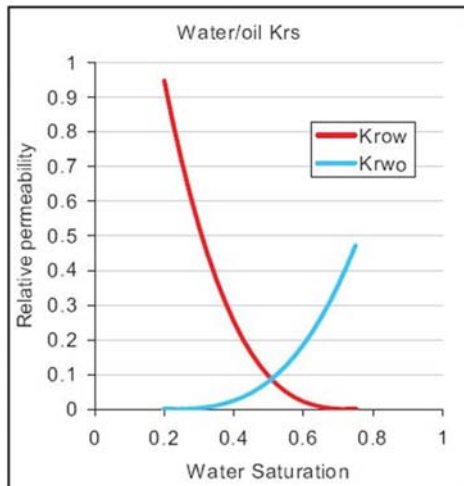
- ▶ **Relative permeabilities are increasing functions of the fluid saturation**
 - The higher the saturation of the fluid, the higher the value of its relative permeability i.e. the fluid effective permeability gets closer and closer to its maximum value
- ▶ **Relative permeabilities depend on**
 - pore geometry
 - nature of the fluids
 - fluid distribution
 - wettability
 - saturation history
- ▶ **For a given porous medium and fluid, relative permeabilities vary depending on the way saturations change (drainage/imbibition)**

Relative permeability

Water-oil relative permeability curves

► To be used to simulate

- Aquifer encroachment into an oil bearing reservoir
- Water injection into an oil bearing reservoir



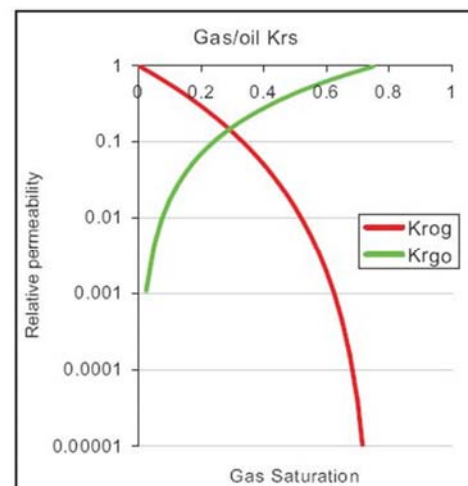
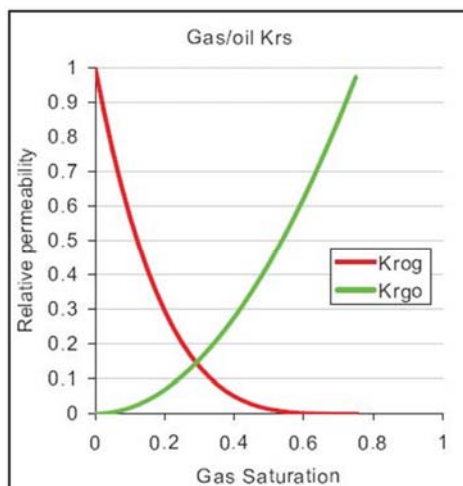
From Gerald Hamon (TOTAL)

Relative permeability

Gas-oil relative permeability curves

► To be used to simulate

- Gas cap expansion
- Immiscible gas injection
- Oil rim encroachment into gas cap



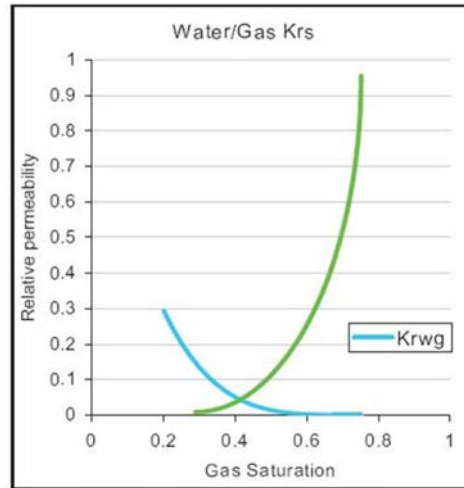
From Gerald Hamon (TOTAL)

Relative permeability

Gas-water relative permeability curves

► To be used to simulate

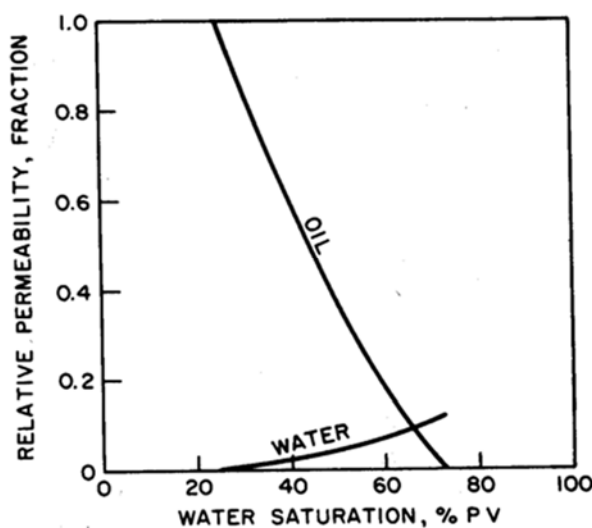
- Aquifer encroachment into a dry gas reservoir



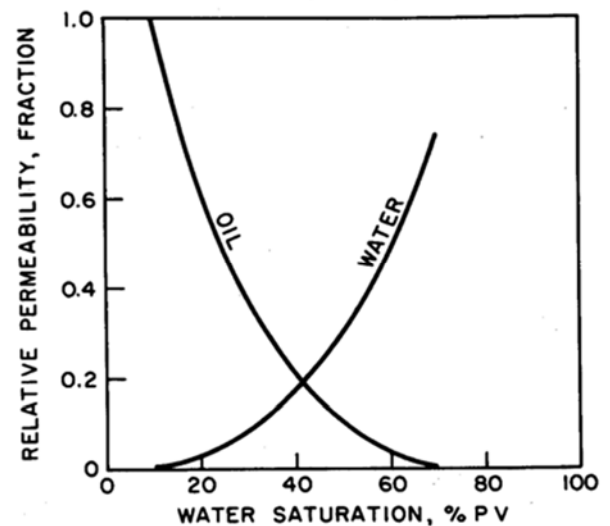
From Gerald Hamon (TOTAL)

Relative permeability

Impact of wettability effect on relative permeability



Strongly water wet



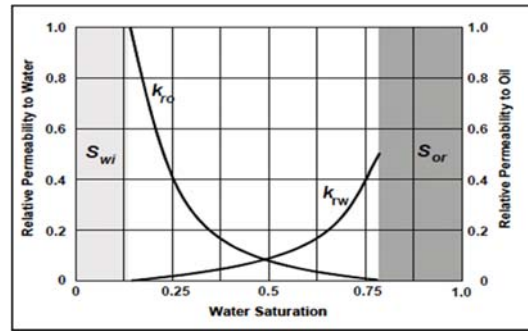
Strongly oil wet

From F. F. Craig, *The Reservoir Engineering Aspects of Waterflooding*, SPE Monograph, 1971

Impact of wettability on relative permeability K_r

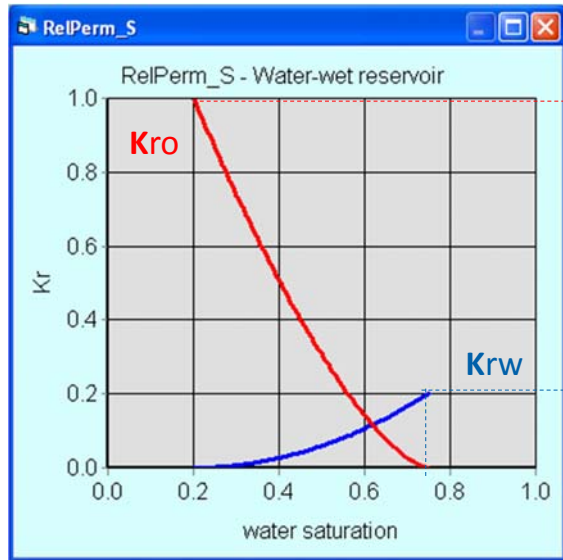
→ K_{ro} decreases when S_w increases

→ increasing water cut reduces permeability to oil

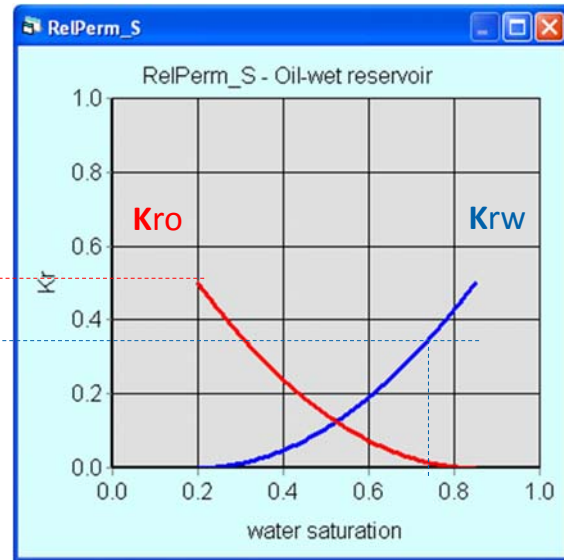


→ **Water-wet:** K_{ro} is higher for same S_w (0.2)

→ **Oil-wet:** K_{rw} is higher for same S_w (0.8)



Water-wet reservoir



Oil-wet reservoir

Relative permeability

Wettability effect on relative permeability - 2

► Craig's rules of thumb

- First rule: in the case of water-wet systems, the maximum water relative permeability (at S_{or}) is much less than the maximum oil relative permeability (at S_{wi}) and the ratio is generally less than 0.3 while in the case of oil-wet systems, the maximum water relative permeability (at S_{or}) is close to the maximum oil relative permeability (at S_{wi}) and the ratio is generally greater than 0.5 approaching 1
- Second rule: the water saturation at which oil and water relative permeabilities are equal is greater than 0.5 for a water-wet system and less than 0.5 for an oil-wet system
- Third rule: the irreducible water saturation is lower for oil-wet systems than for water-wet systems
 - Caution: there may be some exceptions for Craig's rules of thumb especially for water-wet systems where initial water saturation may have a strong influence on the relative permeability curves.

► As a conclusion

- Considering the same densities, oil mobility is higher in water-wet reservoirs while water mobility is higher in oil-wet reservoirs
- **The wetting fluid acts as a « lubricant » for the non-wetting fluid**

Relative permeability

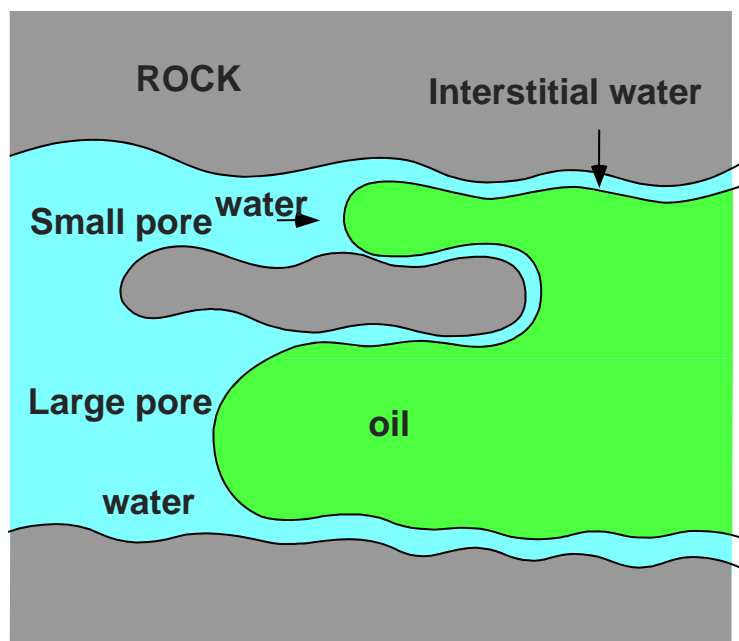
Wettability effect on relative permeability - 3

	Strongly water-wet	Oil-wet
Irreducible water saturation S_{wi}	Generally > 20-25% PV	Generally < 15% PV Often < 10% PV
Saturation at which $k_{ro} = k_{rw}$	> 50% S_w	< 50% S_w
k_{rw} at residual oil saturation by comparison to k_{ro} at irreducible water saturation	Generally < 0.3	0.5 May be up to 1

From W.G. Anderson, *The Effects of Wettability on Relative Permeabilities*, JPT, 1987

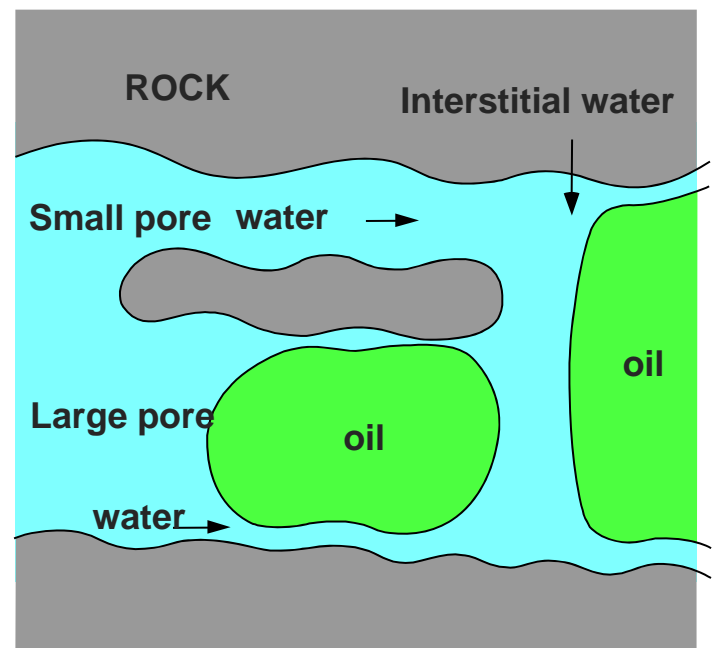
Relative permeability

Relative permeability, wettability and residual saturation



Capillary doublet – water-wet reservoir

Water tends to flow faster in small pores thus isolating large blobs of oil that remain trapped in larger pores => **oil residual saturation**



Recovery Factor

- Displacement Sweep Efficiency = recovery factor at the scale of the porous media (cf. EOR)

$$E_D = \frac{S_{oi} - S_{or}}{S_{oi}} = \frac{1 - S_{wi} - S_{or}}{1 - S_{wi}}$$

- Influence of wettability on E_D :

- Water-wet: $E_D \cong 50\%$
- Oil-wet: $E_D \cong 80\%$

=> better displacement recovery for oil-wet reservoirs but much more production of water

- The best recovery factors seem to be obtained for reservoirs showing mixed wettability (i.e. with a continuous area where wettability is oil-wet interbedded within an area where wettability is water-wet) or slightly water-wet

- A strong wettability character, either oil-wet or water-wet, is generally not favorable for recovery

Relative permeability

Corey normalization

- Saturation normalization

$$S_{wn} = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}} \quad \text{normalized water saturation (for relative permeability)}$$

$$S_{on} = 1 - S_{wn} = \frac{1 - S_{or} - S_w}{1 - S_{wi} - S_{or}} \quad \text{normalized oil saturation}$$

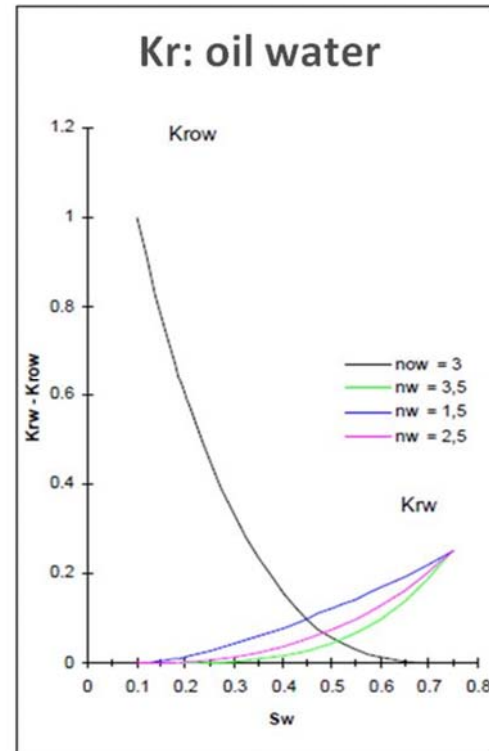
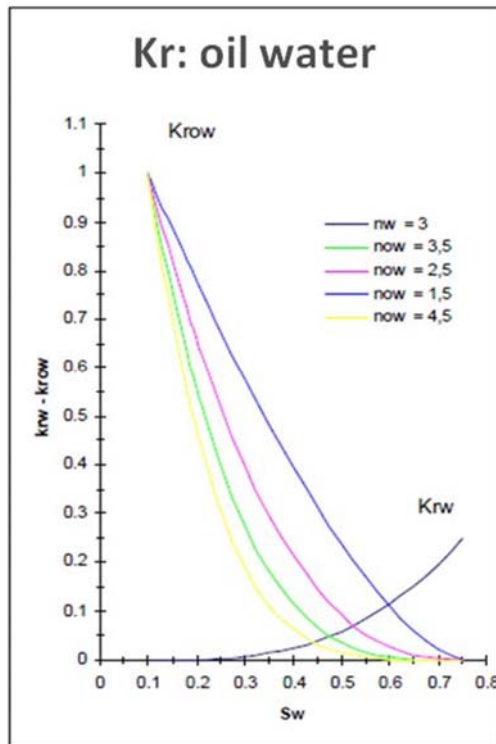
- Corey normalization for relative permeability

$$k_{rw} = k_{rwmax} S_{wn}^{nw} \quad k_{ro} = k_{romax} S_{on}^{no}$$

where:

k_{rwmax}	$k_{rw}(S_{or})$	maximum relative permeability to water
k_{romax}	$k_{ro}(S_{wirr})$	maximum relative permeability to oil
nw		Corey coefficient for relative permeability to water
no		Corey coefficient for relative permeability to water

- Corey coefficients are always greater or equal to 1 and control the shape of the relative permeability curves, hence they are related to the porous network (especially pore geometry) and the wettability



Warning: experimental relative permeabilities may differ from Corey curves



► Relative permeability

- The ratio of effective permeability to absolute permeability
- Absolute permeability is the permeability of the rock when totally saturated with one fluid
- Effective permeability is the permeability of the rock when partially saturated with one fluid

► Relative permeability

- It allows to generalize Darcy's law to multiphase flows in the reservoir
- It is defined by a curve as a function of saturation, typically $k_{ro}(S_w)$ and $k_{rw}(S_w)$

► Relative permeability curves

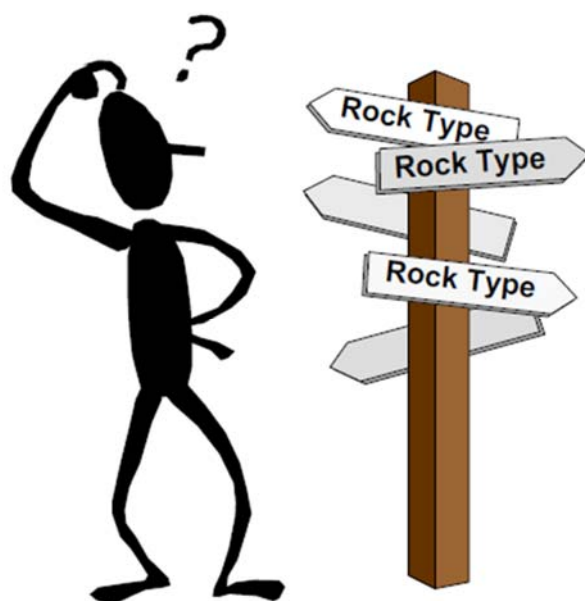
- They depend on wettability
- They govern the flow of fluids (water and hydrocarbons) in the reservoir and have a strong influence on the Recovery Factor



- ▶ **Initial saturation distribution in a reservoir:**
 - It depends on capillary pressures
 - And distance to FWL (Free Water Level) / WOC / GOC
- ▶ **Capillary pressures depend on the wettability as well as depositional facies**
- ▶ **Drainage: a non-wetting fluid displaces a wetting fluid**
 - It typically depicts the initial migration of hydrocarbons into the Reservoir
 - It represents the displacement of water or oil by gas: gas cap expansion
- ▶ **Imbibition: a wetting-fluid displaces a non-wetting fluid**
 - It typically depicts the displacement of oil by water: water flooding production
- ▶ **Relative permeabilities:**
 - When two (or more) fluids flow simultaneously in a rock / in a reservoir, this results in **permeability reduction** for each fluid permeabilities
 - Relative permeability curves are defined as a function of saturation only but they depend strongly on other parameters especially **wettability**

Rock-typing and petrofacies

Rock-typing



Rock type has not the same meaning for everybody

Rock-types – some definitions

20 geologists... 20 different definitions of a Rock-Type!

- A rock that has a set of characteristics sufficiently different from the others...
- A discrete variable, e.g., coded 0 to n
- A 3D volume of rock behaving homogeneously in terms of fluid flow; petrophysics, facies, diagenesis
- Group of rocks with characteristic static, dynamic or geological properties
- Set of lithological properties, having a typical response when measured by a set of recording instruments
- Specific and typical geological nature and history, as well as petrophysical properties
- Sedimentary facies, diagenetic facies, electrofacies, static and dynamic petrophysical characteristics
- A concept to relate depositional facies, diagenetic history, static properties and dynamic properties
- An association of petrophysical characters, attributed to a geological facies
- Classification putting into coherence the sedimentological, log (include well tests and RFT) and petrophysical characteristics
- Group of rocks having a given geological history and homogeneous petrophysical properties, both static and dynamic
- Classification, within a given field, of the rocks based on facies, petrophysics, and log signatures
- Defined by petrophysical parameters (from cores and logs), allowing to establish a reservoir layering
- At coarse scale, average petrophysical characteristics; at fine scale, porous network group
- Well identified porous network, resulting from deposition and diagenesis
- Log signatures, with homogeneous and coherent petrophysical properties (particularly PHI-K)
- Dynamic behavior of a rock (at the scale of the reservoir model)
- Rocks that, even if they can be geologically different, are able to deliver the same quantity of hydrocarbons
- Seismic rock type: any parameters potentially influencing the seismic impedance

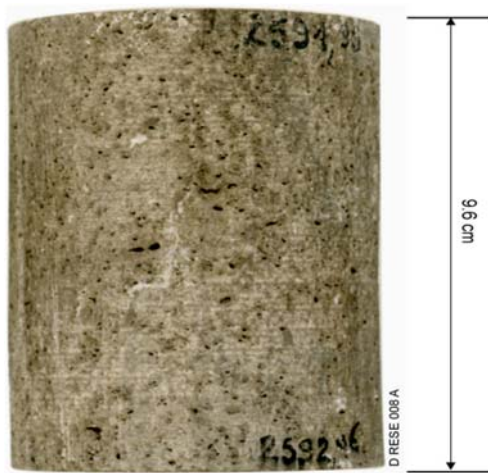
Rock-Typing

Lithofacies, Electrofacies & Petrofacies

- ▶ Rock-typing is a reservoir characterization / reservoir modeling concept allowing to group rocks presenting similar geological and petrophysical properties
- ▶ Rock-typing is based on facies integration
 - Lithofacies defined from stratigraphic framework and core/thin section description
 - Electrofacies defined from logs
 - Petrofacies defined from core analysis when Φ -k-P_c-k_r have similar behavior e.g. k- Φ relationship
- ▶ Rock-typing can be viewed as a preliminary determination of flow units presenting similar storage and flow capacities

Rock-Typing

Lithofacies and Petrofacies – example (1/2)



Lithofacies: Dolomite with vugs
Characteristics: small vugs
 $\Phi = 14,6 \%$
 $K = 0,6 \text{ mD}$

**Same lithofacies
(dolomite with vugs)
but same petrofacies?**



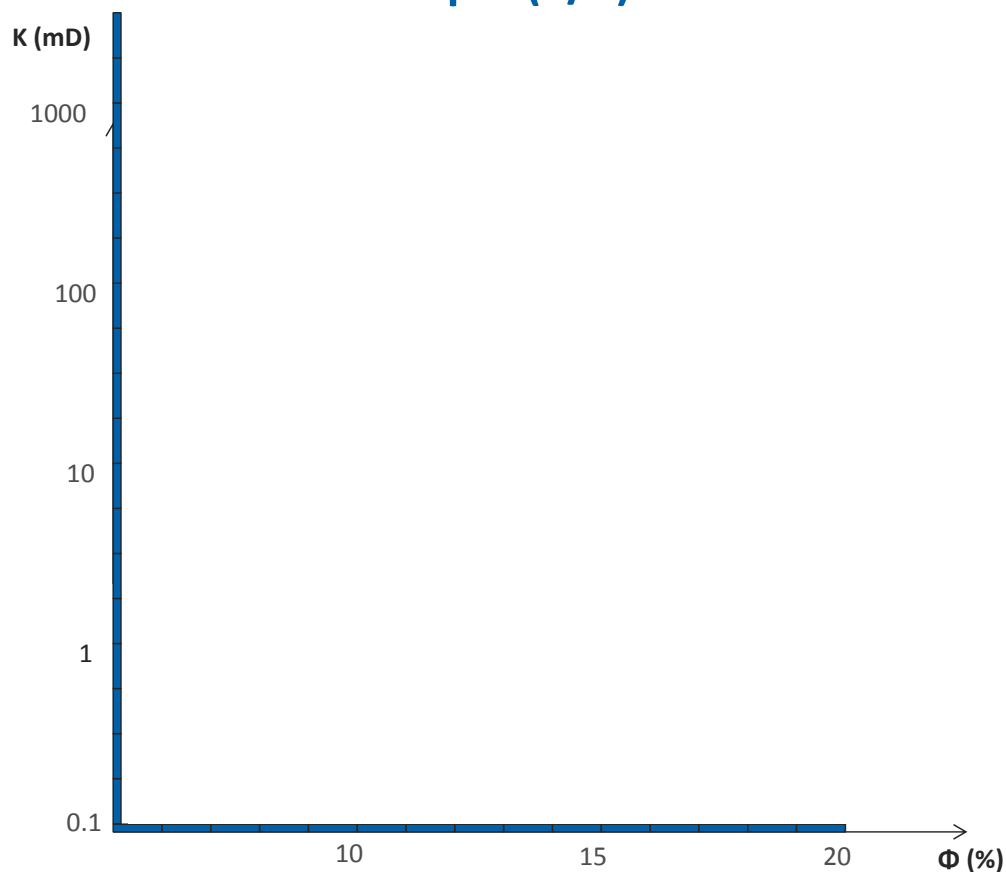
Lithofacies: Dolomite with vugs
Characteristics: Intermediate vugs
Heterogeneous porous network
 $\Phi = 18,8 \%$
 $K = 134 \text{ mD}$



Lithofacies: Dolomite with vugs
Characteristics: Large vugs
 $\Phi = 20,1 \%$
 $K = 1.5 \text{ D}$

Rock-Typing

Lithofacies and Petrofacies – example (2/2)





- ▶ **Rock-typing: a large number of definition including electro-facies, petro-facies, sedimentary facies, etc.**
- ▶ **Rock-typing combines lithofacies, electrofacies and petrofacies**
- ▶ **Petrofacies may be defined by a k - Φ relationship and a capillary pressure curve**
 - Only one capillary pressure curve supposed to represent the behavior of the rock-type
 - Possibly derived from J-function



Open Hole Well Logging and Interpretation

IFPTraining

Contents

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► Wireline Logging operations	196
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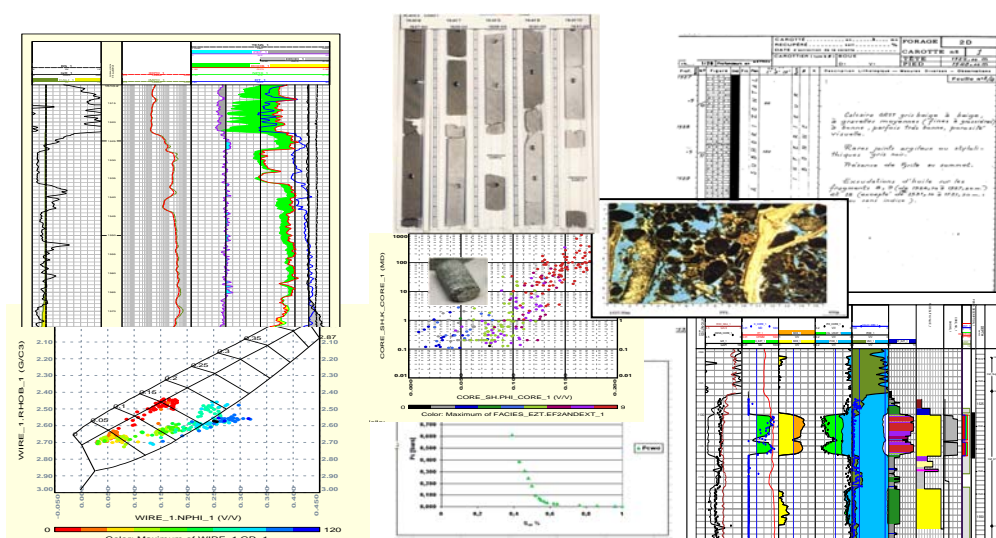
Introduction – Invasion Process

Introduction to Well Logging

Objective of Well Logging

► Why logging wells?

- In order to identify and characterize reservoirs
- But the results of log interpretation (lithology, porosity, saturations) will have to be completed by the description of the geological formations made by the geologist (cuttings and cores)
- Results will have to be compared to core data if any (core porosity and permeability)



General principles of Well Logging

- ▶ **Recording of physical phenomena related to the petrophysical characteristics of the drilled formations and the fluids in place.**
- ▶ **Recording during or after the drilling phase, every 15 cm down to 3 cm (1 foot > 1 inch), in open-hole or cased-hole**
- ▶ **Logs provide continuous detailed in situ information about the subsurface but limited to the wellbore neighborhood (< 1 m from the hole)**
- ▶ **Information from logs may be used by:**
 - Geologists: formation & fluid evaluation and characterization & quantification
 - Drillers: technical information (e.g. cementation quality, sticking point detection for fishing)
 - Reservoir/Petroleum engineers: to analyze all phenomena related to the fluids and their displacement

Introduction to Well Logging

Mud logging / LWD / MWD

- ▶ **Mud Logging**
 - Carried out while drilling the hole.
 - Information is conveyed through the mud or the drill pipe string at the surface where it is gathered by the wellsite geologist and reported on the mud log.
 - It is a description of the geological formations made by the wellsite geologist; the rate of penetration of the drill string, the reporting of oil and gas shows vs. depth.
- ▶ **Measurement / Logging While Drilling (MWD-LWD)**
 - Both types of measurements are carried out simultaneously during drilling.
 - The information is obtained from sensors on the drill pipe string, close to the drilling bit and sent to the surface via the mud
 - It relates both the drilling conditions and the characteristics of the geological formations.

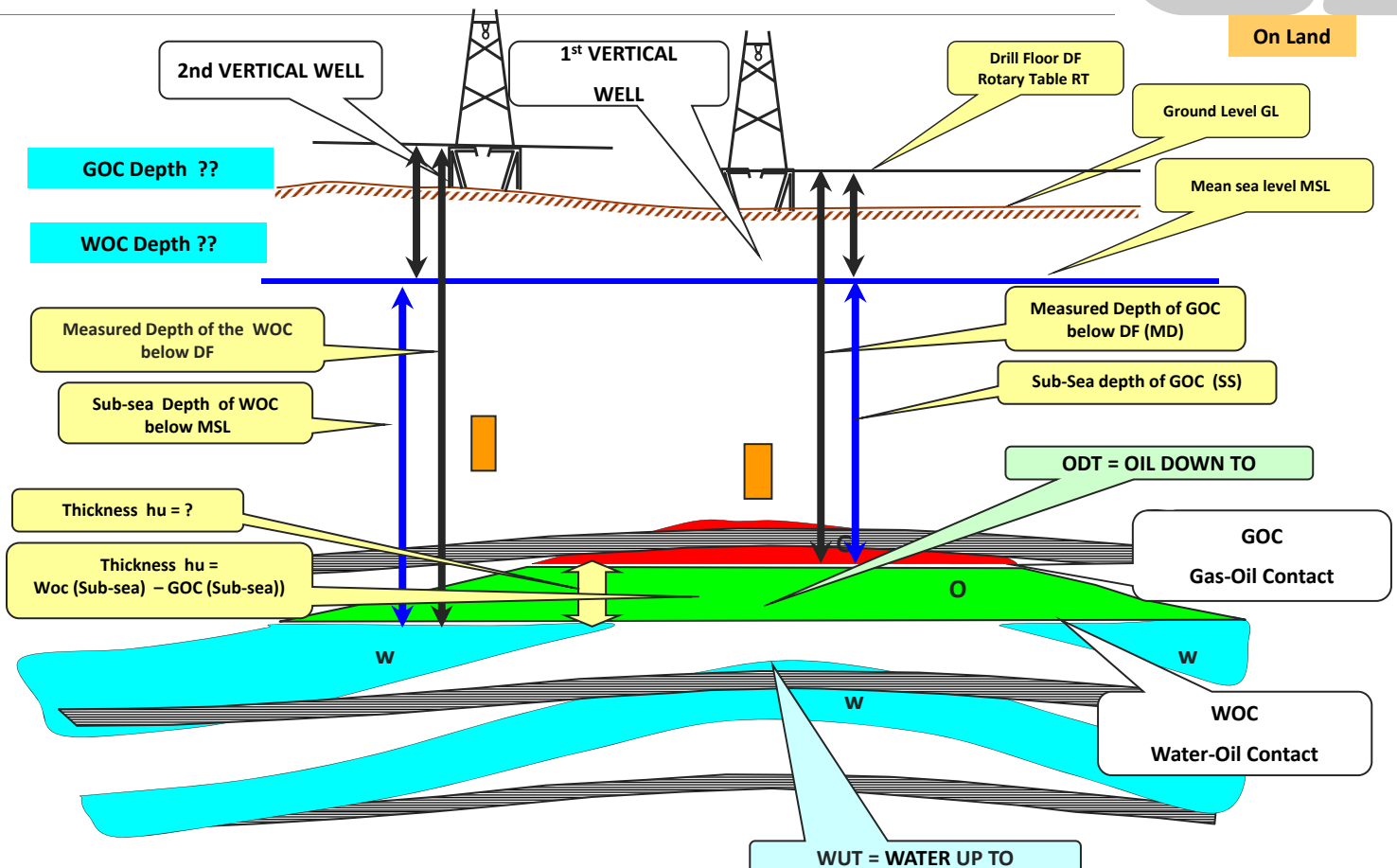
Wireline logging

► Wireline Logging

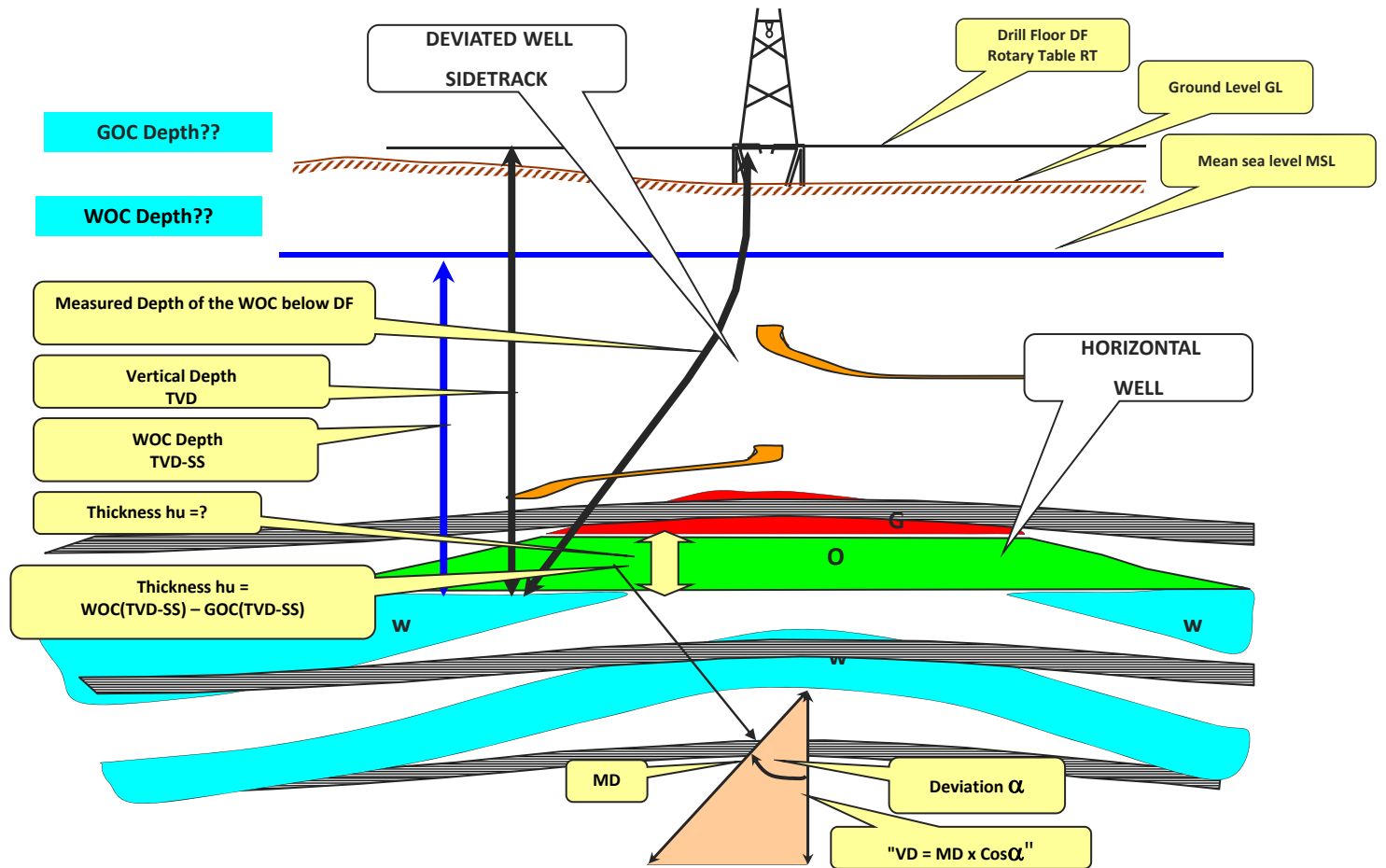
- Wireline logging is carried out by a tool lowered in the well at the end of a cable (wireline) and sent at the surface.
- Wireline logging is carried out in open-hole (OHL) or in cased-hole sections (CHL).
- The log is a measurement of a physical parameter linked with petrophysical characteristics of the drilled formations and the fluids in place as a function of depth.
 - e.g. resistivity that provides information on the fluid saturation and helps determine contacts
- It can also be a record of pressure vs. time

► We will focus on open-hole wireline logs

Vertical wells: fluid contacts



Deviated / horizontal wells: fluid contacts



Mud logging unit



MUD LOGGING UNIT

RIG



INSIDE CABIN
(Geological side)



Geological log



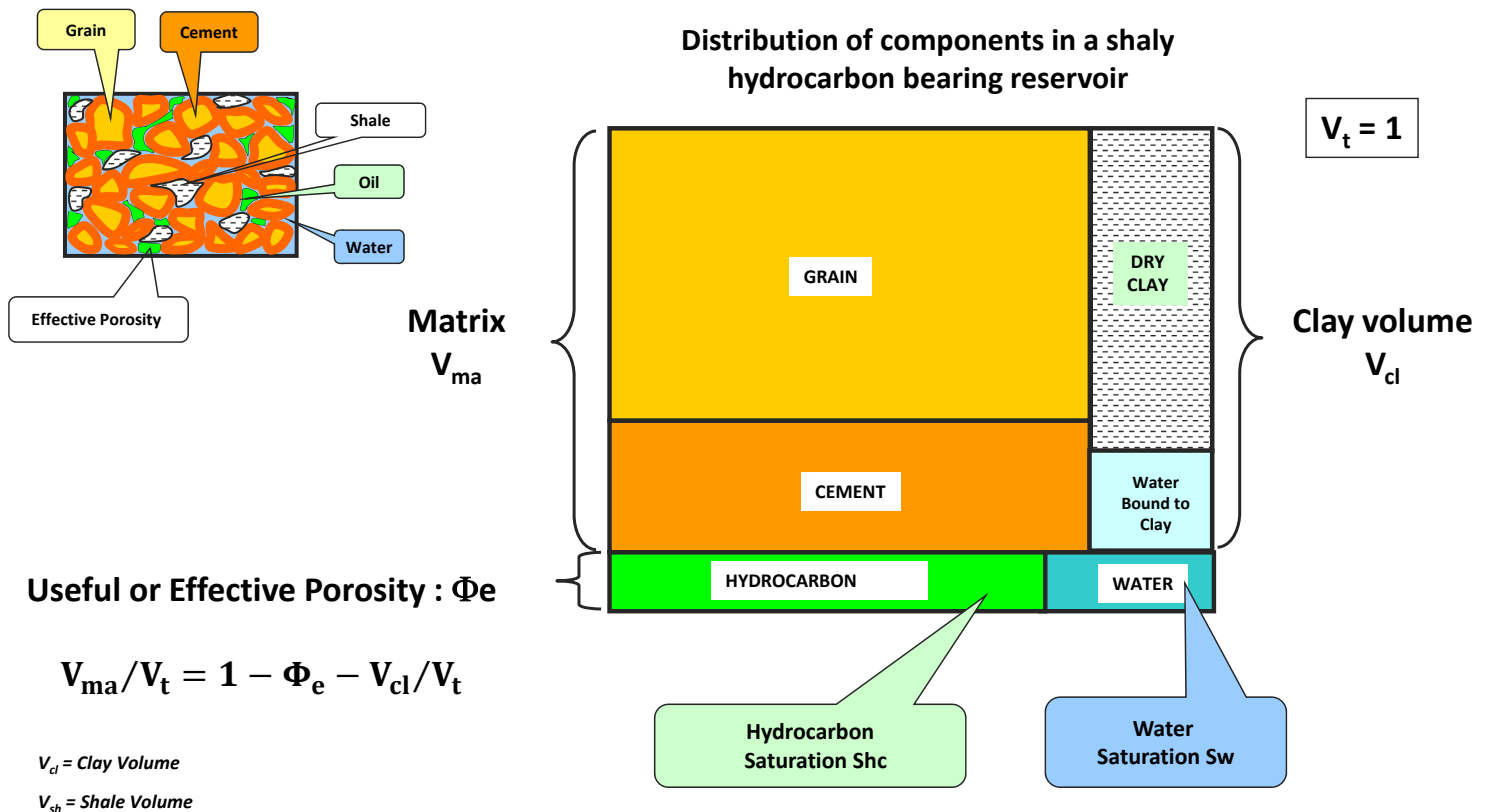
Open Hole Well Logging and Interpretation



Open Hole Well Logging and Interpretation

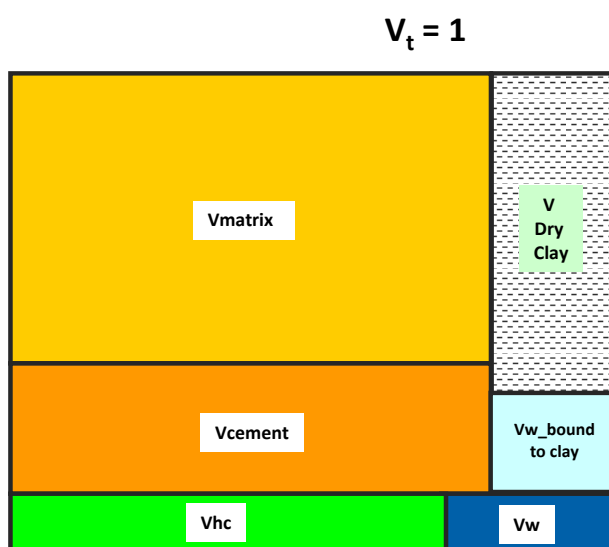
Introduction to Well Logging

Volumetric analysis of a sedimentary rock



Introduction to Well Logging

Notion of porosity (logs)



■ Measurements on cores: Porosity "Lab"

$$\Phi_{Labo} = \frac{V_{total} - V_{solid}}{V_{total}}$$

■ Apparent Porosity PHIA (Density-Neutron Logs)

$$\Phi_A = \frac{V_W + V_{hc} + V_{w_bound_to_clay}}{V_{total}}$$

■ Logs interpretation: effective porosity PHIE

$$\Phi_E = \frac{V_{pore} - V_{w_bound_to_clay}}{V_{total}}$$

► In an hydrocarbon zone:

$$V_{pore} = V_w + V_{hc}$$

$$S_w = \frac{V_w}{V_{pore}}$$

$$S_{hc} = \frac{V_{hc}}{V_{pore}}$$

$$S_w + S_{hc} = 1$$

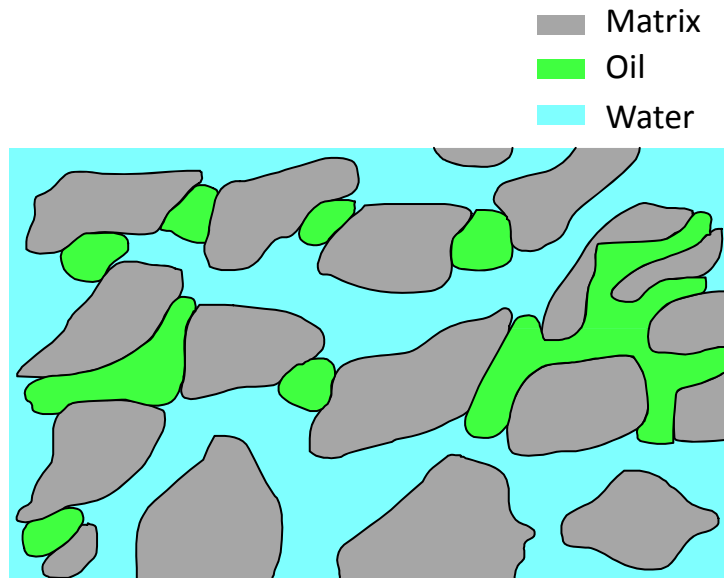
$$S_{hc} = 1 - S_w$$

► In an oil zone

$$S_o = 1 - S_w$$

► In an gas zone

$$S_g = 1 - S_w$$



► Resistance

- By definition, there is a proportionality between the intensity of an electrical current flowing through a conductor and the difference in potential between its extremities
- Ohm's law:

$$I = \frac{\Delta E}{r}$$

Where I is the intensity (A)

ΔE is the difference of potential (V)

r is the resistance (Ω)

► Resistivity and conductivity

- If the length of the conductor increases, the resistance increases in proportion; conversely, if its cross section increases, the resistance decreases in proportion

- Therefore, resistivity R is defined as

$$r = R \frac{l}{A} \quad \text{hence} \quad R = r \frac{A}{l} \quad \text{in } \Omega \cdot \text{m}$$

- Conductivity C is defined as the inverse of resistivity

$$C = 1/R \quad \text{in } \text{S} \cdot \text{m}^{-1}$$

Archie's law (2)

► Archie's law

- The total resistivity of a rock sample R_t is a function of its water saturation S_w :

$$R_t = \frac{R_o}{S_w^n} = \frac{a}{\phi^m} \cdot \frac{R_w}{S_w^n} = F \cdot \frac{R_w}{S_w^n} \Rightarrow S_w = \sqrt[n]{F \cdot \frac{R_w}{R_t}}$$

Where

R_w is the resistivity of the formation water

R_o is the resistivity of the sample fully saturated with water: $R_o = \frac{a}{\phi^m} \cdot R_w$

F is **the formation resistivity factor**: $F = \frac{R_o}{R_w} = \frac{a}{\phi^m}$

a is a constant; usually $a=1$

n is a constant called the **saturation factor**; usually $n=2$

m is a constant called the **cementation factor**; usually $m=2$ but $1.3 < m < 2.5$ with usually higher values for carbonates than for sandstones

- This equation is the **Archie's law** and is **valid only in clean formation** ($V_{\text{shale}} = 0$)

► Resistivity index

$$I = \frac{R_t}{R_o} = \frac{1}{S_w^n}$$

Introduction to Well Logging

Archie's law in the water zone

► Archie's law in the water zone

$$S_w = 1 \Rightarrow R_t = R_o = F \cdot R_w = \frac{a}{\phi^m} \cdot R_w$$

► The proportionality factor FF is called Formation Resistivity Factor

- It is the ratio of the resistivity of a formation sample fully saturated with water (100% water) R_o to the formation water resistivity R_w
- It depends on lithology and on rock porosity (determined in laboratory)

► How to use it

- R_o is measured from the logs $\Rightarrow R_w$ is deduced
- Value of R_w from logs can be compared to other measurements, especially from the water salinity measured in laboratory from samples (e.g. coming from tests like RFT/MDT)

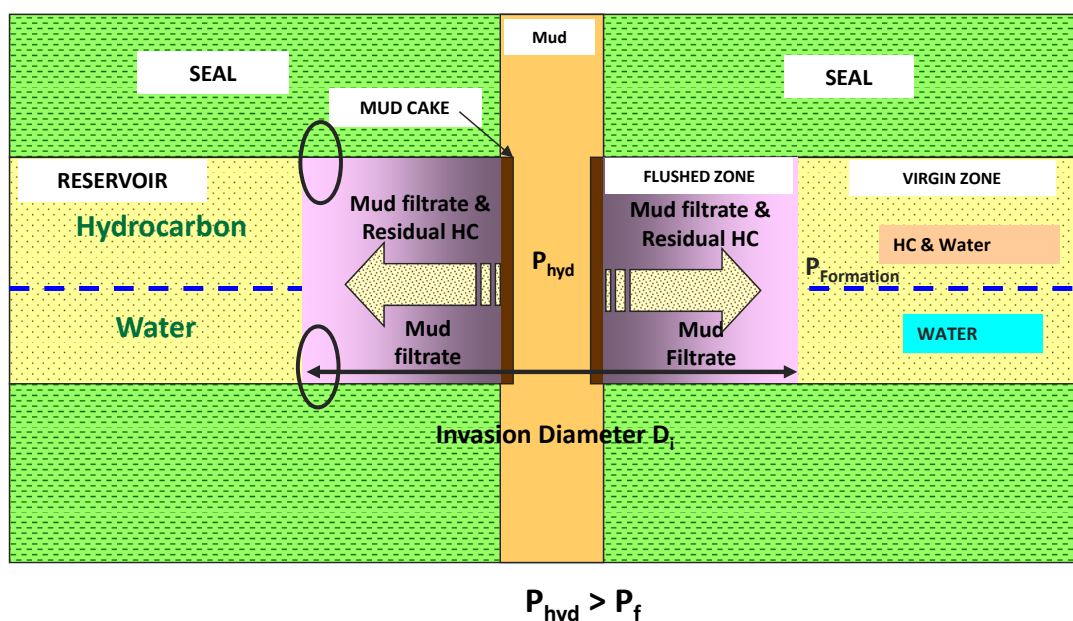
► Archie's law in the hydrocarbon zone:

$$S_w = \sqrt[n]{F \cdot \frac{R_w}{R_t}} = \sqrt[n]{\frac{a}{\Phi^m} \cdot \frac{R_w}{R_t}}$$

► How to use it

- $R_t \Rightarrow$ measured from resistivity logs (Latero log, Induction log)
- $R_w \Rightarrow$ measured from logs (SP or resistivity logs in the water zone) or from samples in laboratory (through salinity)
- $\Phi \Rightarrow$ measured from logs (Neutron & Density) or from core samples in laboratory
- $a, m, n \Rightarrow$ measured from samples in laboratory
- S_w is deduced and correspondingly **hydrocarbon saturation** $S_{hc} = 1 - S_w$

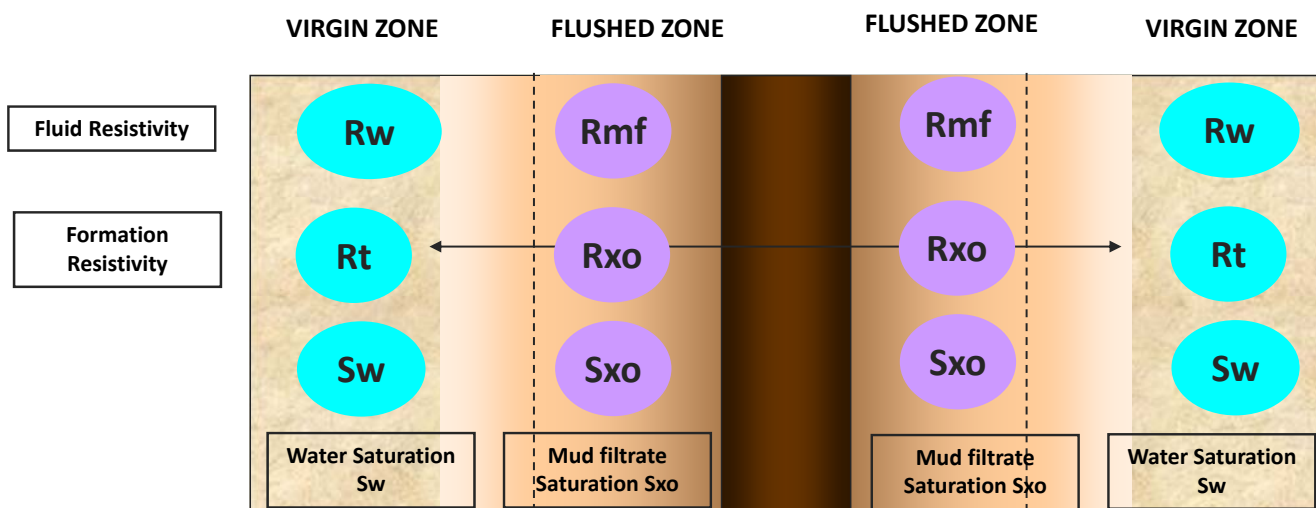
Invasion of reservoirs by the drilling fluid



► Invasion process

- Assuming a porous and permeable reservoir rock between two impermeable beds
- The mud density is chosen in order to create a hydrostatic pressure in the wellbore **higher** than the fluid pressure in the reservoir, preventing the formation fluid from entering the wellbore => **the mud is forced into the porous formation**
- The mud solids, too large to fit through the pore throats, are stopped at or near the borehole wall => the mud is **filtered** and form the **mudcake**
- The liquid part of the mud, called the **mud filtrate**, moves on into the formation, sweeping the original movable fluids (formation water / hydrocarbon) away from the wellbore => **invasion** of the formation.
- The zone filled with mud filtrate is called the **flushed zone** while the zone beyond the flushed zone is the **virgin zone**
- In almost all the cases there will be residual fluids in the flushed zone including the original formation water (at irreducible saturation), residual oil, and residual gas.
- When the mudcake is thick enough to become **impermeable**, the invasion process stops.
- The invasion process is characterized by a **diameter of invasion**

Case of a well drilled with water based mud (WBM)



Virgin zone => $R_t = \frac{a}{\phi^m} \cdot \frac{R_w}{S_w^n} \Rightarrow S_w \Rightarrow S_{hc} = 1 - S_w$ water & hydrocarbon saturations

Flushed zone => $R_{xo} = \frac{a}{\phi^m} \cdot \frac{R_{mf}}{S_{xo}^n} \Rightarrow S_{xo} \Rightarrow S_{hr} = 1 - S_{xo}$ mud filtrate & residual HC saturations

Clean Formation, without shale (Vsh = 0)

Archie's equation in the flushed zone (1)

- ▶ Considering a clean HC bearing formation invaded by water-based mud
- ▶ Archie's equation in the virgin zone

$$R_t = \frac{a}{\Phi^m} \cdot \frac{R_w}{S_w^n}$$

where R_t is the total formation resistivity, R_w the water resistivity and S_w the water saturation

- ▶ Archie's equation in the flushed (invaded) zone

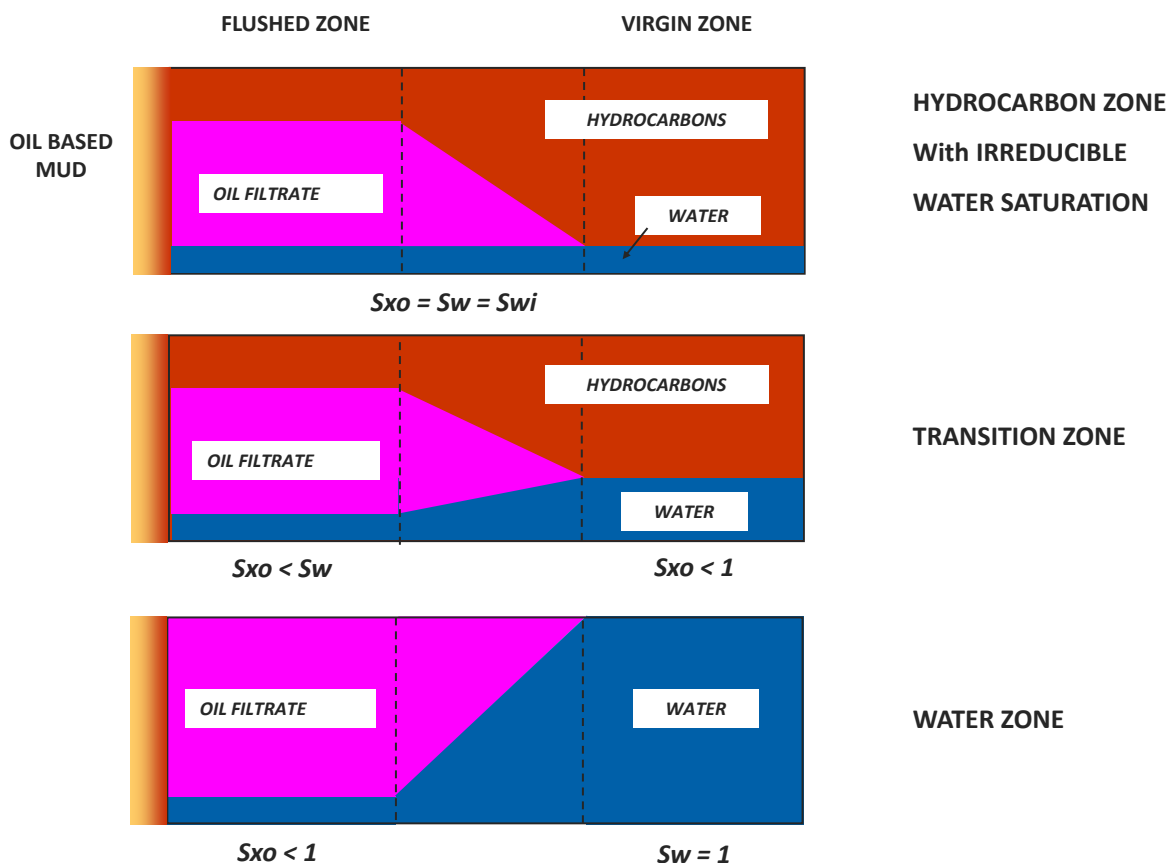
$$R_{xo} = \frac{a}{\Phi^m} \cdot \frac{R_{mf}}{S_{xo}^n}$$

where R_{xo} is the invaded formation resistivity, R_{mf} the mud filtrate resistivity and S_{xo} the mud filtrate saturation

- ▶ From these equations, we may calculate S_w and S_{xo} and the corresponding HC saturation S_{hc} and residual HC saturation S_{hr}
 - In the case of wells drilled with oil based mud (OBM), R_{mf} and R_{xo} are not available and S_{xo} and S_{hr} cannot be determined

Introduction to Well logging

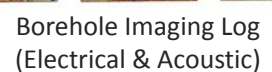
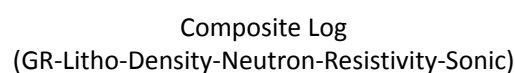
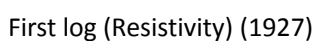
Invasion in Oil Based Mud



A photograph of an oil well drilling rig in a desert environment. The rig is a tall, complex structure with various pipes and mechanical components. It is situated on a flat, sandy landscape under a bright blue sky with scattered white clouds. In the background, there are some industrial buildings and containers. The image is overlaid with a semi-transparent blue and yellow geometric pattern consisting of several overlapping trapezoidal shapes. The text "Wireline Logging operations" is written in a bold, blue, sans-serif font on the left side of the image, partially overlapping the blue geometric shapes.

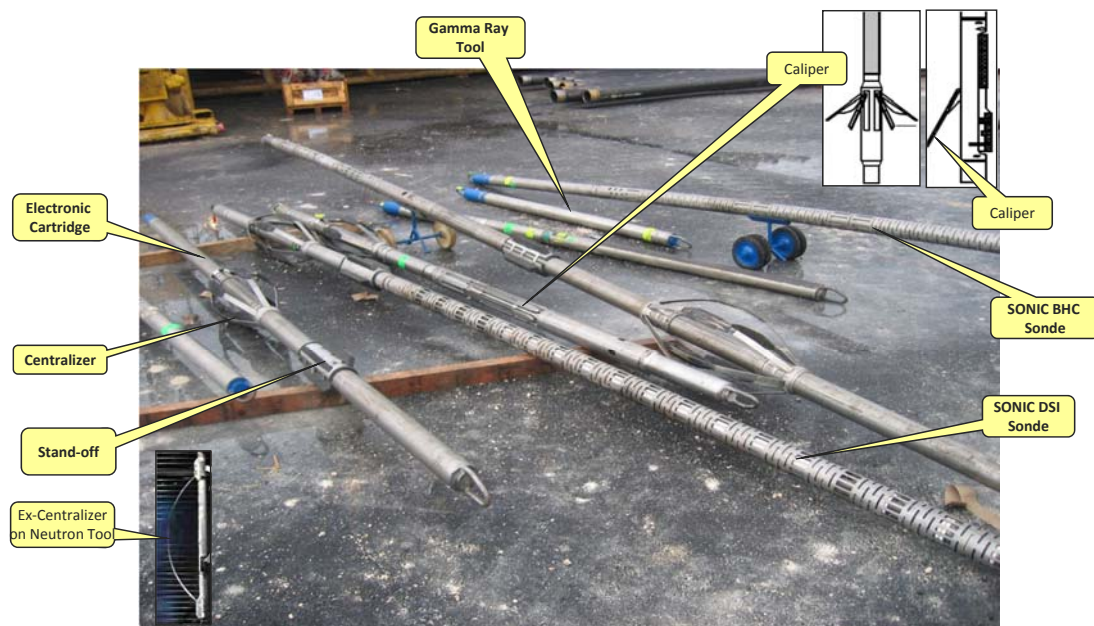
Wireline Logging operations

September 1927: First “Electrical Coring” done in Pechelbronn, Alsace, by Conrad et Marcel Schlumberger.



Wireline Logging operations

Some logging tools



A selection of downhole logging tools being prepared for a job. Most tools are 3 3/8" or 3 5/8" in diameter. They consist of measurement packages, housed in sondes of various geometries together with their electronic control cartridges.

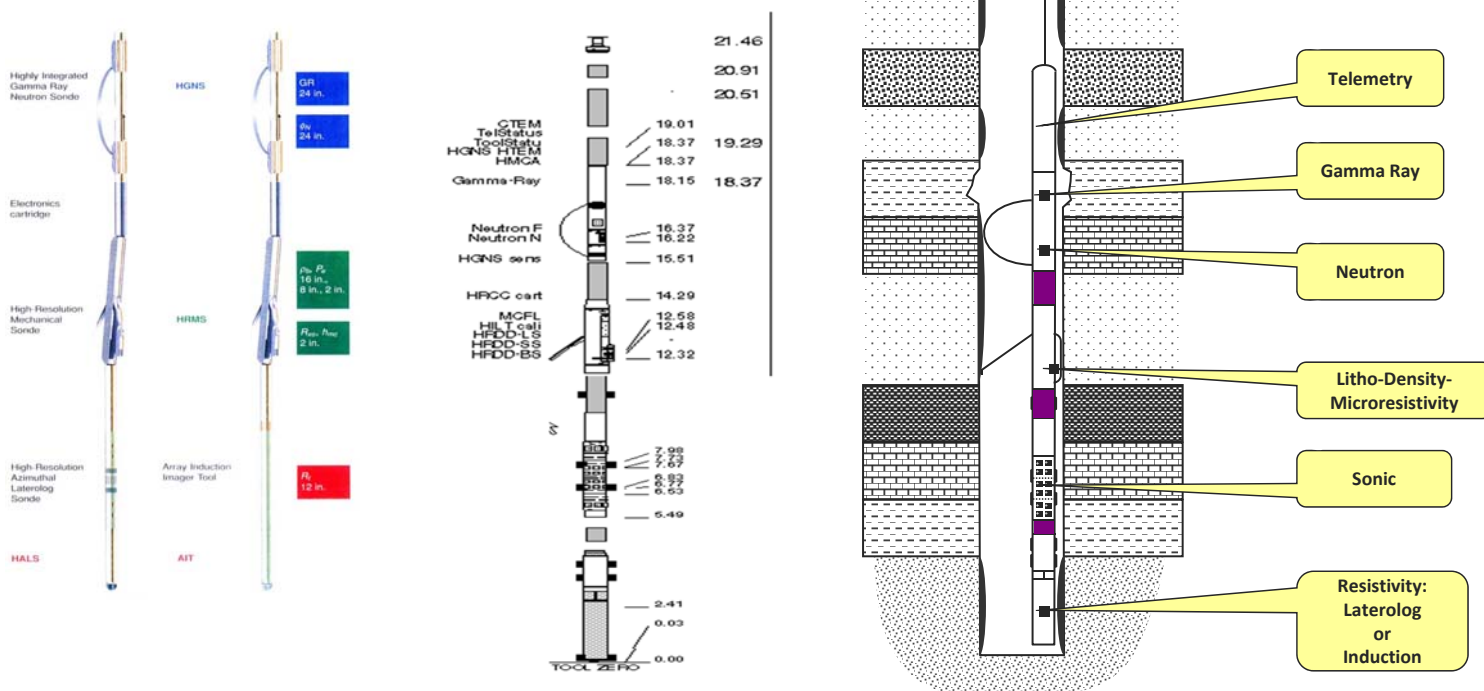
In order to apply sensor pads directly to the well bore, some tools have either a caliper arm that opens hydraulically when down hole or an ex-centralizer.

The electronic cartridges treat the raw signals, perform first order data manipulation, monitor the tools performance, and transmit the data up-hole to the surface acquisition equipment.

Wireline Logging operations

Tools combination

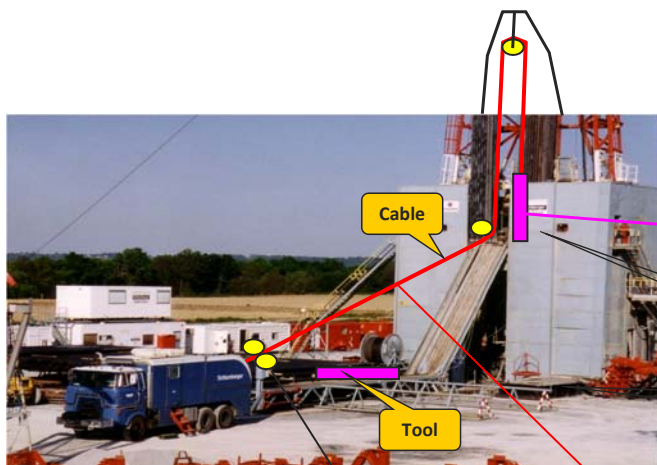
Logging tools combination: PEX Platform Express (Schlumberger)



Wireline Logging operations

Rig-up

The kelly bushing positioned on the rotary table is used while drilling to rotate the drill pipes. Nowadays, this has become obsolete as people use mud power drive devices.



Rig view and Logging Truck



The tool head is the link between the cable and the logging tools. It includes 3 grooves in which 3 thermometers maximum can be positioned.

Head of the tool

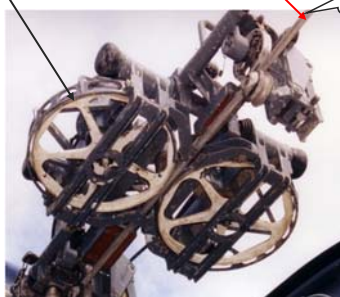


Bottom of the tool

When the bottom of the logging tool string is at the level of the Drill Floor, the depth is set at « Zero ». On the log header the information will be: Log measured from « Drill Floor » DF



Kelly Bushing KB rotating while drilling

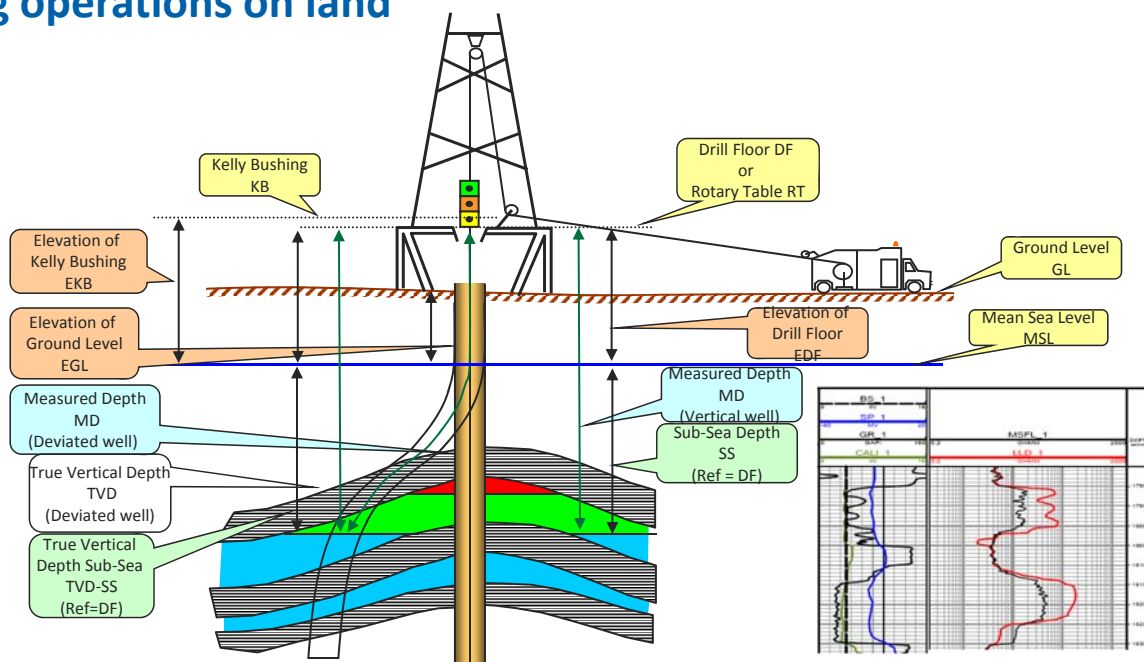


Depth Measurement

The measuring wheels device is used to measure the depth accurately.

Wireline Logging operations

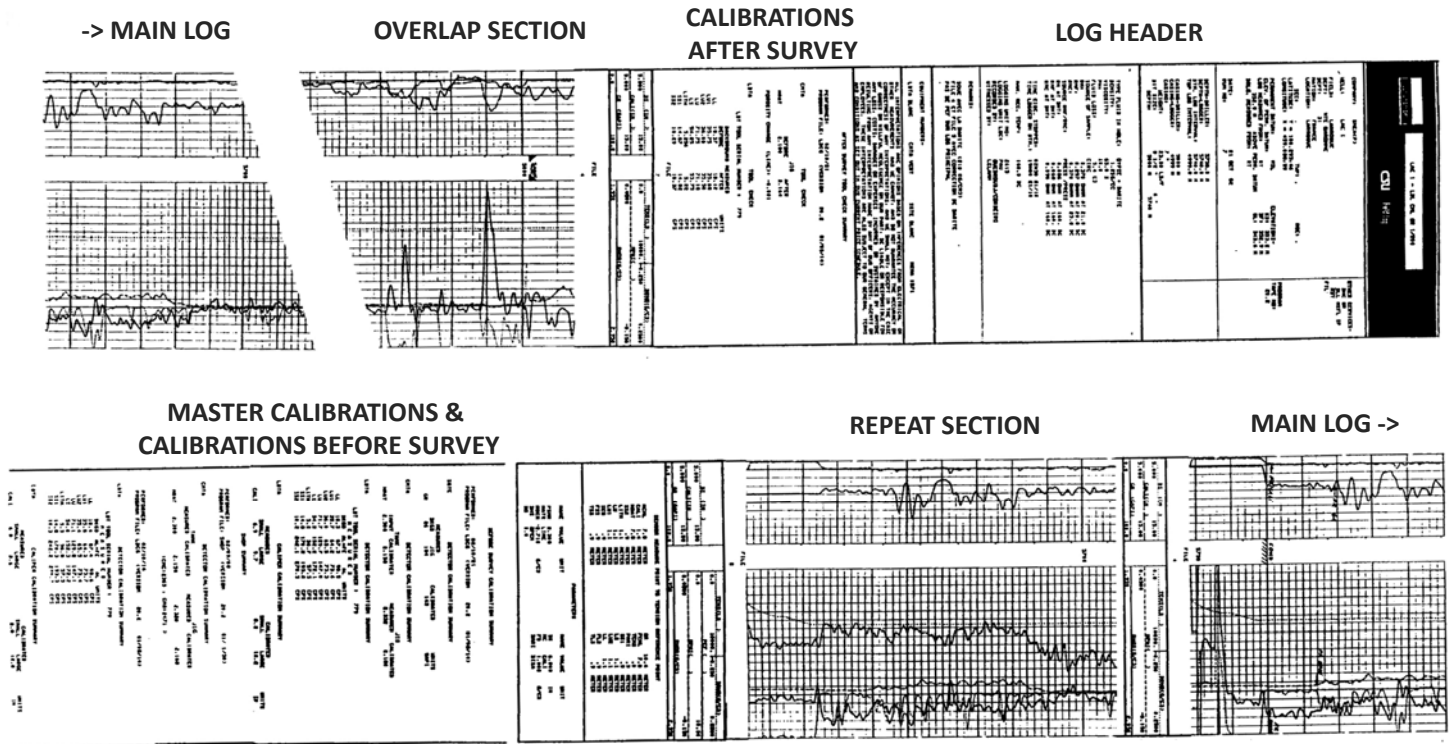
Logging operations on land



The tools that are connected together are ready to be lowered in the vertical well. In deviated well, the tools can also be lowered as long as the deviation is not too high. Above approximately 50 degrees, the tools will not go down by their own weight.

Above 50 degrees deviation and in horizontal wells, the tools can be connected at the end of the drill pipes and lowered in the well together with the wireline logging cable; this is called TLC, Tough Logging Conditions.

Note the various depths: Measured Depth (MD), True Vertical Depth (TVD), True Vertical Sub-Sea depth (TVD-SS) and the surface references: Ground Level (GL), Drill Floor (DF), Rotary Table (RT), Kelly Bushing (KB)



► Natural phenomena recording

- Well diameter
- Natural radioactivity
- Formation temperature

Caliper
Gamma Ray
Temperature

► Artificially stimulated phenomena recording

- Formation resistivity
- Formation lithology & porosity

Resistivity, Induction
Neutron, Density, Sonic

→ Fluid
→ Rock

► Tools

- Source/receiver spacing
 - Depth of investigation
 - Vertical resolution
- Centered in borehole or pressed against wellbore (pad)

► Determination of both reservoir zones and fluid content

- Invasion (mud cake detection)
- Identification of fluids and respective saturations



Open Hole Logging tools

Open Hole Well Logging and Interpretation

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Open Hole Logging tools

Main tools to be addressed

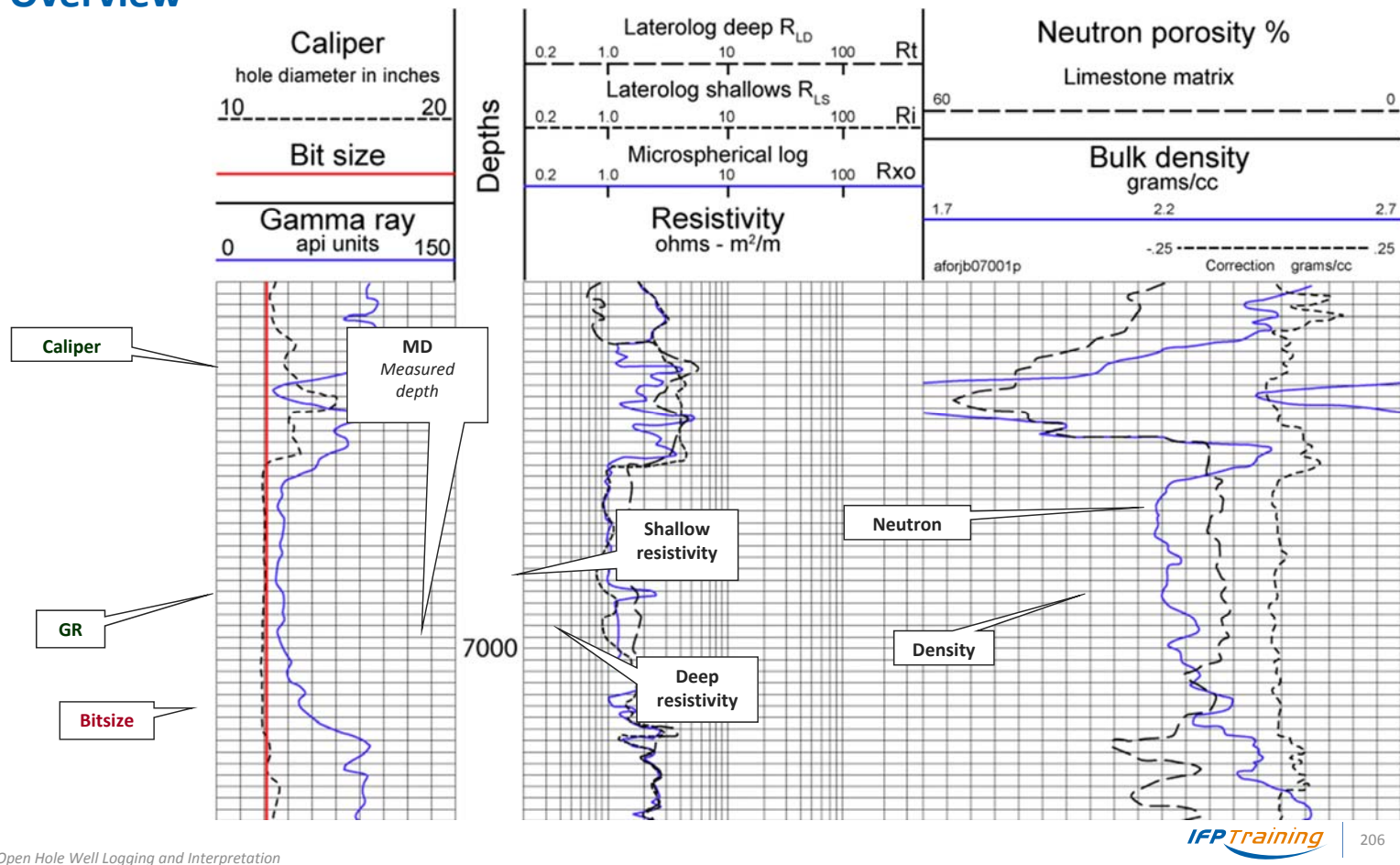
- ▶ Caliper
- ▶ Gamma Ray
- ▶ Spontaneous Potential
- ▶ Induction, Laterolog and Resistivities
- ▶ Litho-density – Neutron – Sonic
- ▶ Pressure and fluid sampling
- ▶ Permeability logs

Open Hole Well Logging and Interpretation

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Overview



Caliper

Principle

► Caliper measures the borehole effective diameter

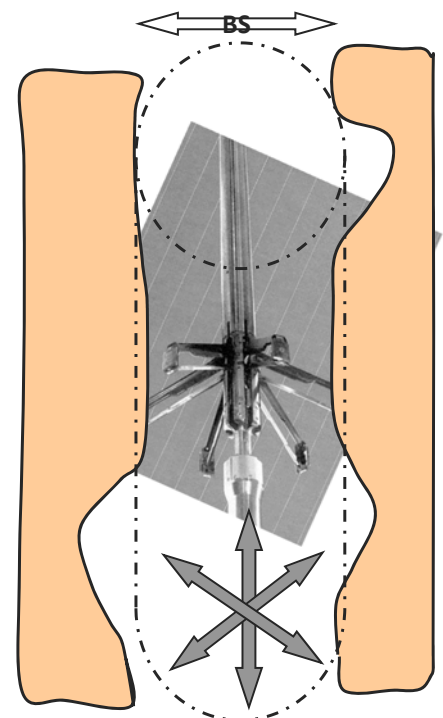
- 2 opposites arms (simple)
- 4 or 6 arms, 2 by 2, in diagonal

► Measurement in constant drilling phase

- Comparison with bit size (BS)
- Fluctuates around bit size values

► Applications

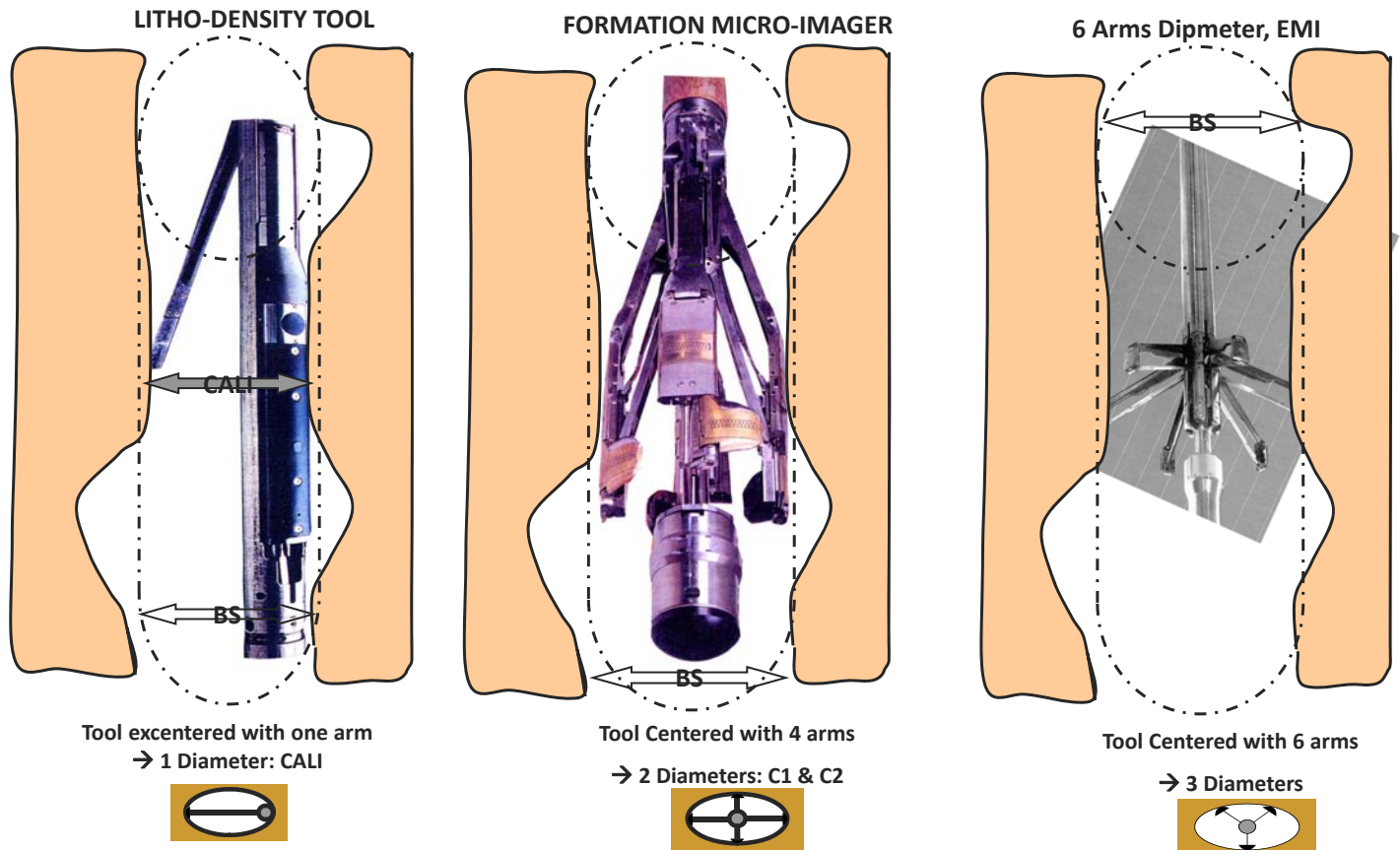
- Potential mud-cake location ($\varnothing < BS$)
- Caves, irregular wellbore ($\varnothing > BS$)



6 arms caliper (3 diameters)

Caliper

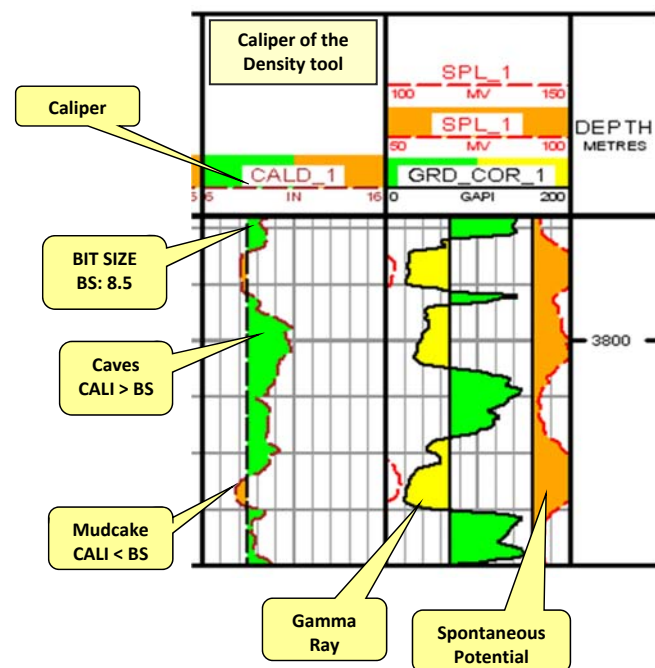
Caliper types



Caliper

Applications

- The caliper is basically used to determine the hole volume hence the **volume of cement** needed for the future casing
- Alternatively, the caliper may help to identify **caves** where $CALI > BS$ and **mudcake** where $CALI < BS$
 - The presence of a restriction may indicate mudcake ($\Rightarrow h_{mc}$) i.e. the presence of reservoir zone ; but presence of restriction in front of a shale may indicate swelling (montmorillonite shale) !
 - The presence of caves may indicate shale formation; but in front of a sandstone reservoir caves may indicate an unconsolidated formation!
 - In front of caves, the measurements of density, neutron, sonic, microresistivity will be affected by the mud \Rightarrow **the knowledge of caves is essential for the logs QC**



Caliper log with the Bit Size (BS=8.5") on a 6 to 16 inches scale.

Gamma Ray

Gamma Ray and Spectral Gamma Ray tools

► Gamma Ray tool:

- Measurement of the total natural radioactivity (GR), Unit = API

► Spectral Gamma Ray tool:

- Spectral Gamma Ray (SGR): U + K + Th
- Corrected Gamma Ray (CGR): K + Th

There are 2 types of GR, the Corrected Gamma Ray (CGR) and the Spectral Gamma Ray (SGR) tools.

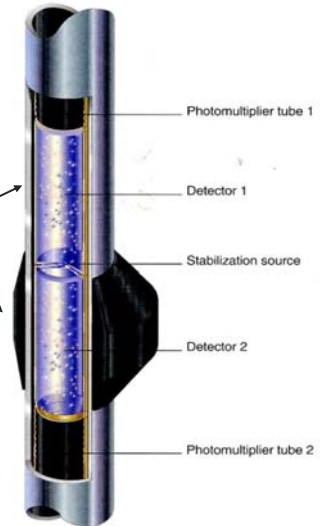
The SGR sonde has a dual detector configuration.
The CGR is the total GR corrected for Uranium.

Nowadays, Neutron and SGR form a unique sonde, when run in combination with porosity and resistivity tools.

SCINTILLATION DETECTORS

HNGS sonde (Schlumberger)

Units: SGR & CGR in API units
K in %, Th & U in ppm



Gamma Ray

Natural radioactivity

► In sedimentary rocks, natural radioactivity arises from the elements coming from the series of Thorium, Uranium and Potassium

- Potassium K
 - Potassic shales (illites)
 - Potassic evaporites
 - Potassic feldspars
 - Micas
 - Minerals (with K)
 - Mud (with KCl)
- Thorium Th
 - Detritic shales
 - Minerals with Th (heavy minerals)
- Uranium U
 - **Organic matter** (typically within shales)
 - Minerals with U

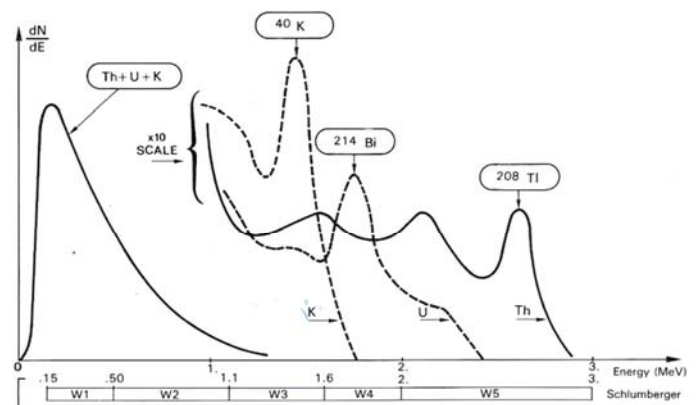
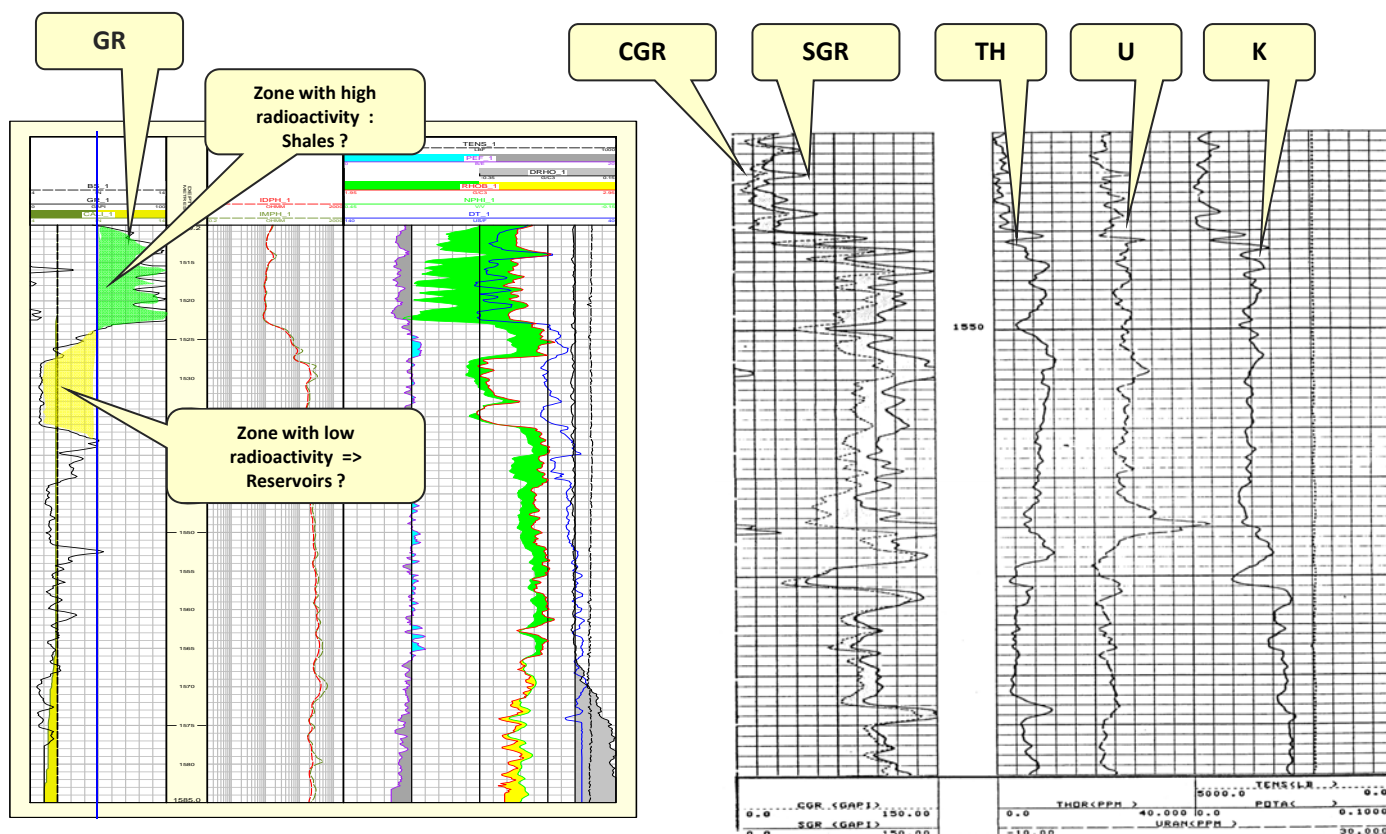


Fig. 3 : Potassium, Thorium and Uranium spectra obtained with the Na I (Tl) crystal detector - Position of the windows

Gamma Ray

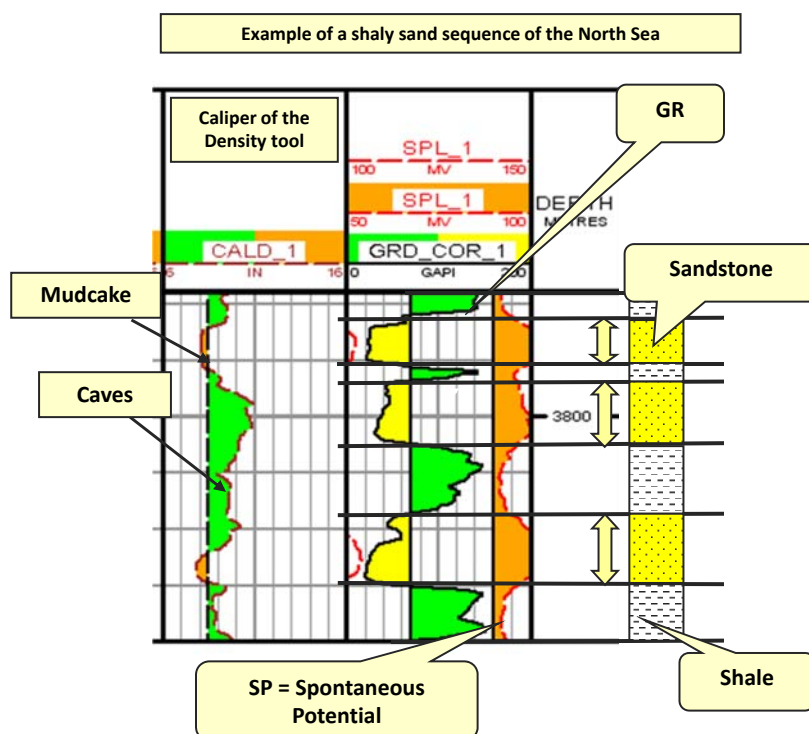
Examples of GR and Spectral GR logs



Gamma Ray

Gamma Ray applications

- **Identification of shale formations and reservoir formations**
 - In simple shale-sand sequence, GR can distinguish between shale and sandstones.
 - In complex lithology, spectral GR, together with Th and K will help to distinguish a radioactive sandstone reservoir zone from a shale zone.
- Geological correlations
- **Estimation of shale content (V_{sh})**
- Detection of radioactive minerals
- **Type of clay minerals**
- Depth matching of subsequent logs
- Cased hole depth correlations
- In CHL, together with Sonic & CCL (Casing Collar Locator) evaluate the quality of cementation



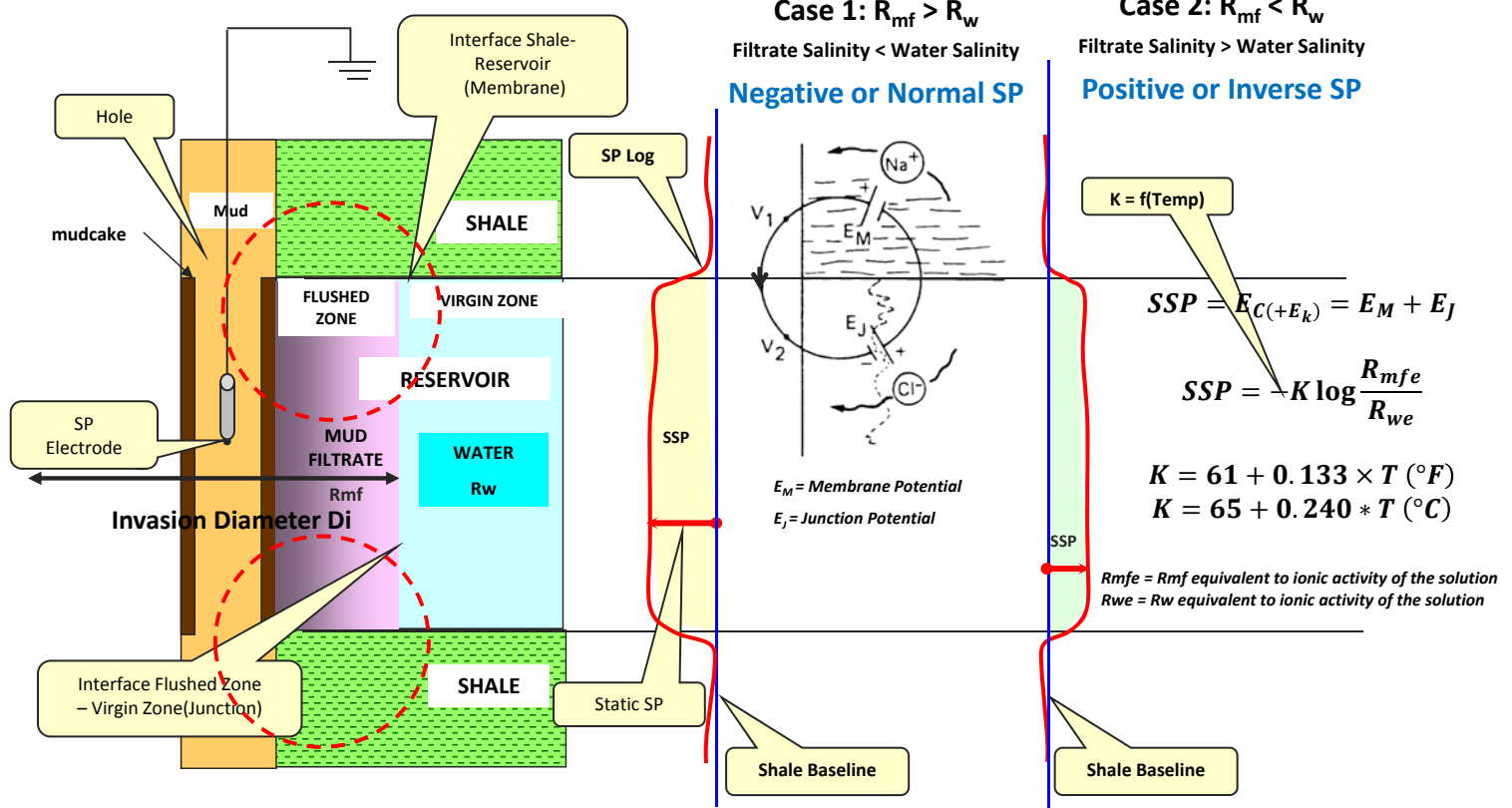
Spontaneous Potential

Principle

- ▶ SP log records continuously **the difference in electrical potential** between a **movable electrode within the borehole** and a **surface reference electrode**.
- The potential difference is due to the **difference in salinity** between the formation water in the virgin zone and the mud filtrate in the invaded zone.
- SP values in front of shale beds define a straight line known as **the shale base line**.
- In front of permeable formations, SP log shows generally a depart from the shale base line called the **deflection** that may define a constant line defining the **Static SP (SSP)**.
 - Note however that in a reservoir where both mud filtrate and formation water have similar salinities, the deflection could be nil.
- SSP depends on the ratio between R_{mf} and R_w .
 - The scale is relative, going from the baseline to the curve itself.
 - If the formation water salinity is greater than the mud filtrate salinity (most common case), the deflection is to the left and negative, and called **Normal SP**
 - Otherwise the deflection is to the right and positive, and called **Inverse SP**
- Note that SP log **cannot be recorded in holes filled with non-conductive muds**, typically oil based muds (OBM)

Spontaneous Potential

Normal and Inverse Spontaneous Potential



Applications

- Determination of bed boundaries
 - In simple shale/sand sequence, the SP, like the GR, can help to identify shale and sandstone reservoirs.
 - In carbonate sequence, the SP, can help to identify porous, permeable zones.
- Geological correlations
- **Detection of permeable layers**
- Evaluation of R_w

$$SSP = -K \log \frac{R_{mfe}}{R_{we}}$$

where SSP is given by the log

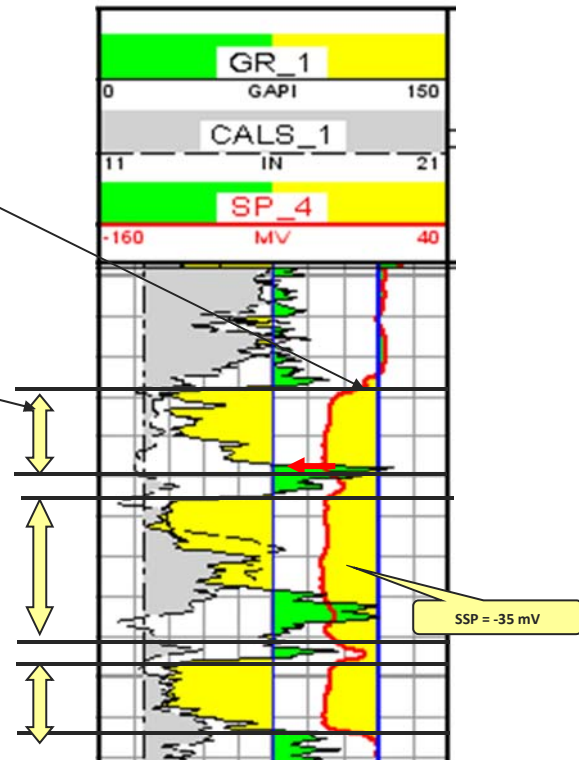
R_{mfe} is supposed to be known

K is estimated from temperature

$$K = 61 + 0.133 \times T (^{\circ}F)$$

$$K = 65 + 0.240 \times T (^{\circ}C)$$

- **Evaluation of shale content (V_{sh})**



Resistivity measurements

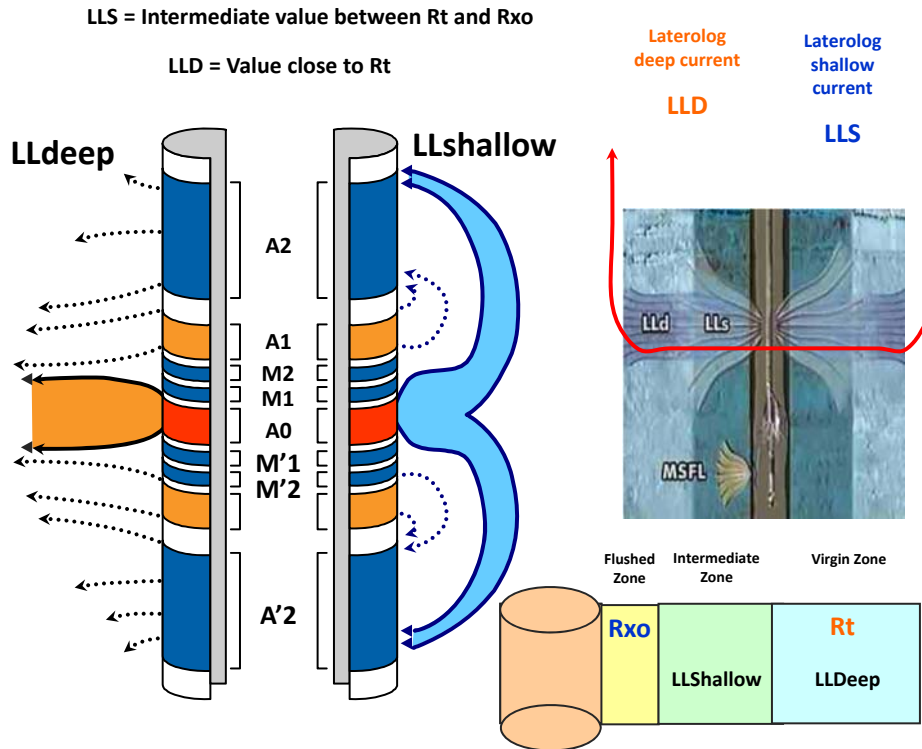
Laterologs - Principle

► Laterologs measure the formation resistivity

- either far from the borehole, i.e. the virgin zone resistivity
- or in the intermediate zone between the flushed and the virgin zones.
- two depths of investigation => two tools: **Laterolog Deep (LLD)** and **Laterolog Shallow (LLS)**
- The device measures the voltages and magnitudes of the electric currents associated with a series of electrodes mounted at the surface of the sonde.
- The sonde geometry ensures that LLD current travels far into the virgin zone while for the LLS, the measured current is allowed to diverge more quickly.
- Laterologs require **direct electrical contact** with the formation, which is provided through the drilling mud => **they work only in Water Based Mud** and work best in conductive muds with low values of R_m , R_{mf} and R_{xo} .
- For quick qualitative interpretation, LLD is considered as a value close to total resistivity R_t .
- The LLD is usually combined with the MSFL - Micro Spherically Focused Log

Resistivity measurements

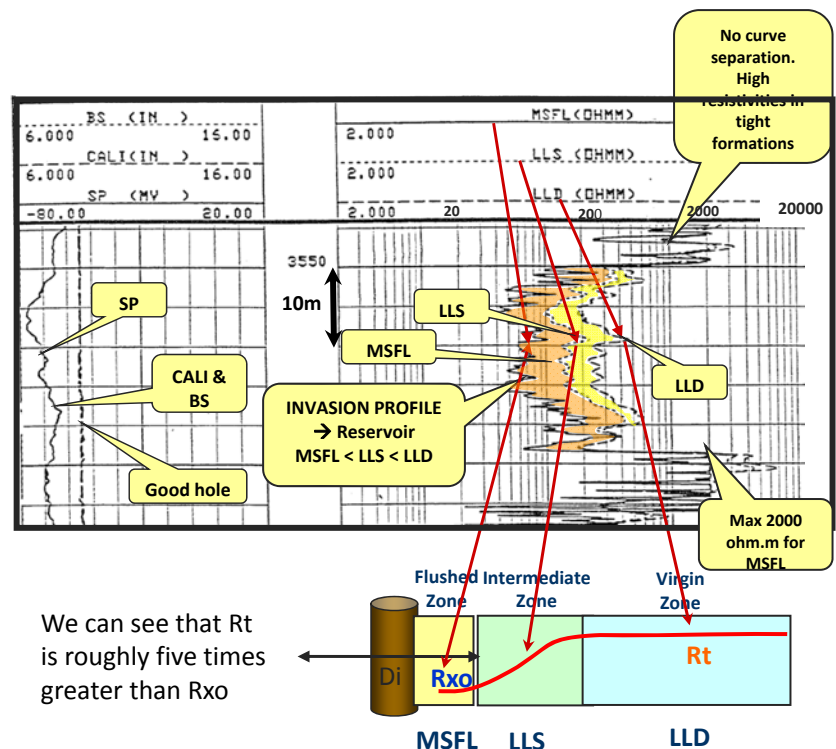
Laterologs - Principle (2)



Resistivity measurements

Laterolog-MSFL dual combination

- MSFL = Micro Spherically Focused Log with a very low depth of investigation.
- Each curve is responding to the **formation resistivity at the depth of investigation it is designed to read**
- The variation of resistivity into the reservoir zones can be build from these curves => **resistivity profile**
 - MSFL < LLS < LLD in the reservoir zone.
 - The lower resistivity in the flushed zone allows the current to easily flow to the virgin zone

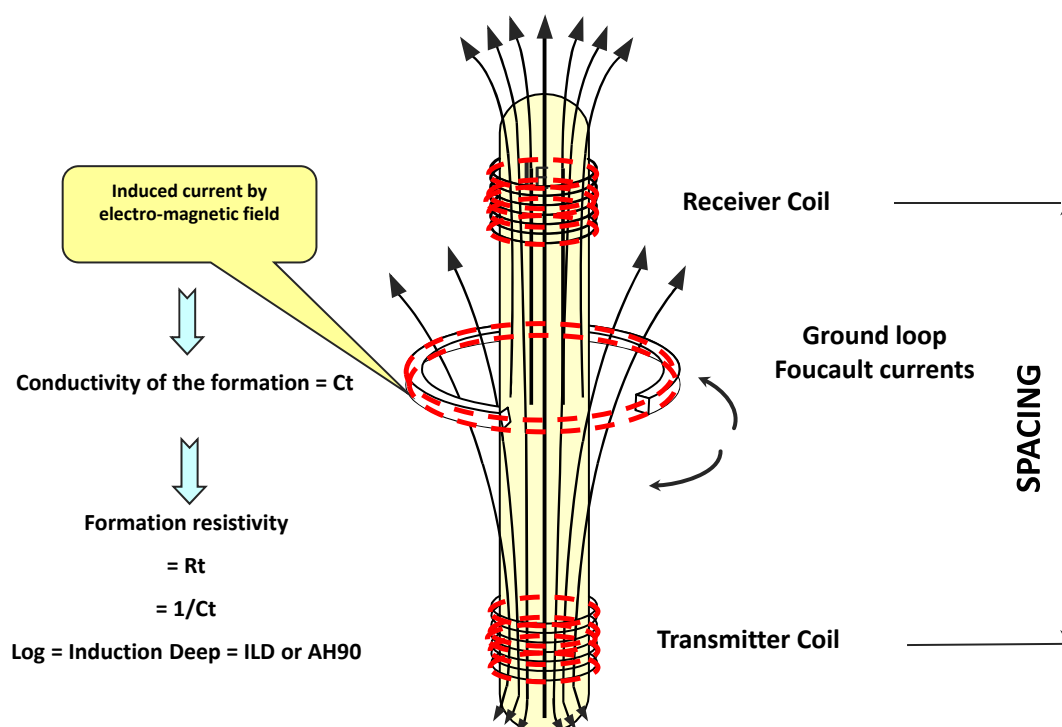


Induction tool - Principle

- ▶ The induction tool measures the **formation conductivity through the voltage of induction currents**
 - Considering a 2-coil configuration, the tool has one transmitter coil and one receiver coil.
 - The transmitter oscillator sends a high frequency (typically 20kHz) alternating current into the transmitter coil at the bottom of the tool.
 - This current creates a primary magnetic field in the formation, which induces an electric current to flow in loops in the formation around the borehole, perpendicular to the tool / bore hole axis.
 - These “**ground loop**” currents create a secondary magnetic field that in turn induces a current and a related **voltage** in the receiver coil.
 - This voltage is proportional to the **formation conductivity C_t** .
 - The induction tool does not require a direct contact with the formation and does not require conductive muds. It works best in **fresh Water Based Mud** or **Oil Based Mud** and with low formation resistivities.
 - The Induction Log Deep **ILD** is directly the inverse of the conductivity C_t
 - For quick qualitative interpretation, **ILD is considered as a value close to R_t** .

Resistivity measurements

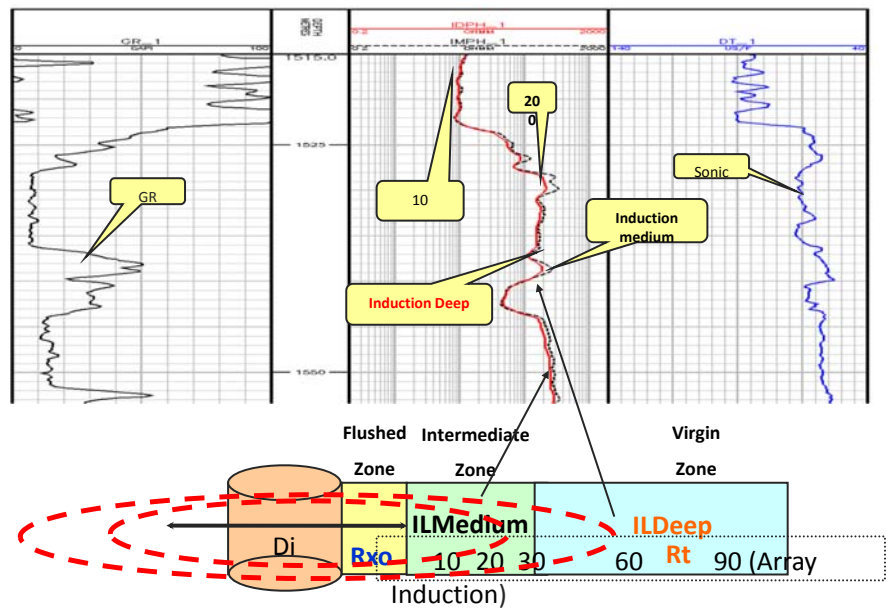
Induction tool - Principle



Resistivity measurements

Dual Induction – Sonic – GR log

- The simple 2-coil system is no longer in use. Arrays of transmitters and receivers allow focusing measurements for various depth of investigation and vertical resolution.
- Example of Dual Induction Log (in combination with GR and Sonic tools) in an OBM drilled well.
 - With appropriate coil spacing, two induction curves with different depths of investigation are presented: the **deep induction (ILD)** and the **medium induction (ILM)**.



The upper section where the GR is high and where the resistivities ILD and ILM read around 10 Ohm.m is a **shale** layer.

In the lower section, ILD and ILM read almost exactly the same high values, about 200 Ohm.m. High resistivities can be found in **tight formations** but also in porous formations containing either fresh water or **hydrocarbons**.

Resistivity measurements

Limitations of resistivity logs

► Laterologs tools

- Can only be used in Water Based Mud
- Cannot be used in Oil Based Mud

► Best results are obtained with Laterologs

- If the ratio R_{xo} / R_t is low ($R_{xo} < 2 * R_t$)
- If the formations have high resistivity

► Microresistivity tools

- Can only be used in Water Based Mud
- Cannot be used in Oil Based Mud
- Can detect thin beds, permeable zones, fractures
- Are very sensitive to bad quality holes

► Induction tools

- Can be used in fresh Water Based Mud (WBM) or Air
- Can be used in Oil Based Mud (OBM)

► Best results are obtained with Induction:

- If ratio R_{xo} / R_t is high ($R_{xo} > 2 * R_t$)
- If formation resistivity is low or not too high
- If the mud is relatively fresh

Applications of resistivity measurements

- ▶ LLDeep, ILDeep or AH90 = values close to R_t

$$R_t = \frac{R_o}{S_w^n} = \frac{a}{\Phi^m} \cdot \frac{R_w}{S_w^n} = F \cdot \frac{R_w}{S_w^n}$$

- ▶ Microresistivity logs = values close to R_{xo}

$$R_{xo} = \frac{a}{\Phi^m} \cdot \frac{R_{mf}}{S_{xo}^n}$$

- ▶ Resistivity measurements are used to:

- Identify the reservoirs
- **Detect the water-oil contact**
- Determine R_t , R_{xo} and the invasion diameter D_i
- Determine the resistivity R_w of the water and the water salinity
- **Determine the water and hydrocarbon saturation**

$$S_w = \sqrt[n]{\frac{a}{\Phi^m} \cdot \frac{R_w}{R_t}} \Rightarrow S_w \Rightarrow S_{hc} = 1 - S_w$$

- Determine the residual hydrocarbon saturation in the flushed zone

$$S_{xo} = \sqrt[n]{\frac{a}{\Phi^m} \cdot \frac{R_{mf}}{R_{xo}}} \Rightarrow S_{xo} \Rightarrow S_{hr} = 1 - S_{xo}$$

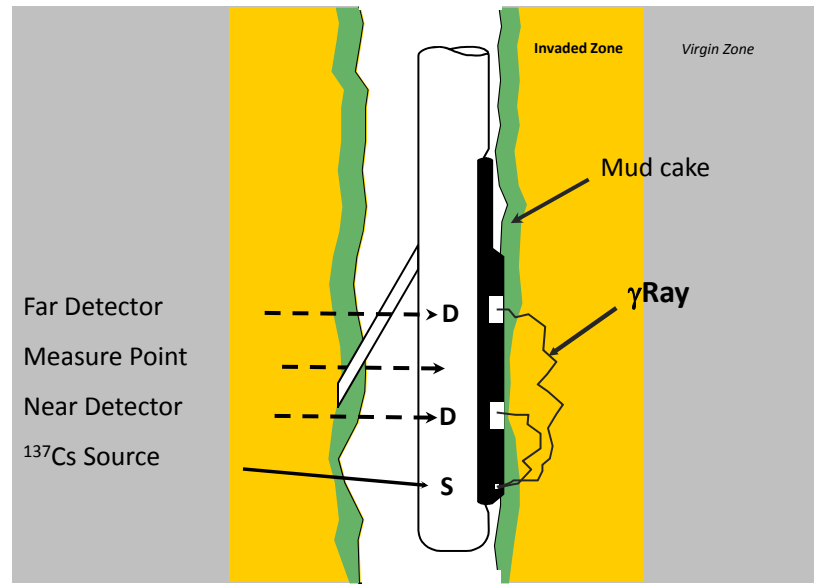
Porosity and Lithology measurements

Litho-density - Principle

- ▶ The litho-density tool is designed to measure the **formation density** RHOB (in g/cc) and the **Photoelectric Absorption Factor** PEF of the formation.

- A radioactive source emits Gamma Rays (high energy photons) into the formation.
- After interaction with the electrons surrounding the atoms of the formation, they are counted and analyzed on 2 detectors, the close detector and the remote detector.
- The density log and the PEF log are derived from these counts.
 - Note that in recent HRMS sonde from SLB, the density skid includes also a set of electrodes to get a micro-resistivity called MCFL, close to R_{xo} .
- The density measurements may be affected by borehole conditions, especially by **caves**

Litho-density – Principle (2)



Litho-Density Tool

Density Tools and Logs

FDC: Formation Density Compensated → Logs RHOB et DRHO

LDT: Litho-Density Tool (> 1980) → Logs RHOB, DRHO et PEF

Porosity and Lithology measurements

Density and PEF definition

► Photoelectric Absorption Factor

$$PEF = \left(\frac{Z}{10}\right)^{3.6} \text{ with } Z = \text{atomic number}$$

- PEF is a function of the lithology and the values are little affected by the fluids (see chart PEF – RHOB)
- Warning: PEF is very sensitive to the presence of barite, therefore it might be reading too high and be wrong

► Density

$$\rho_b = (1 - \phi_u) \cdot \rho_{ma} + \phi_u \cdot \rho_f \text{ for clean formation without shale } (V_{sh}=0)$$

- Density varies with lithology, porosity and fluid density

Density and PEF values

► Common matrix values of PEF and Density are listed below

- For limestone, sandstone and dolomite, the matrix density values correspond to 0% porosity.
- Note that for limestone containing water of density 1g/cc, the measured value RHOB is exactly the bulk density. That is due to the fact that the master calibration for density tools is based on water-filled limestone blocks of known densities.
- For values of densities and PEF for other minerals, refer to the last 2 pages in the appendix section of this course.

Mineral	PEF (barn/e)	Density ρ_{ma}
Limestone (CaCO_3)	5.1 (5.1 → 4.4)	2.71 g/cm ³
Dolomite (CaCO_3 , MgCO_3)	3.1 (3.1 → 2.7)	2.85 g/cm ³
Sandstone (SiO_2)	1.8 (1.8 → 1.6)	2.65 g/cm ³
Salt (NaCl)	4.7	2.04 g/cm ³
Anhydrite (CaSO_4)	5.1	2.98 g/cm ³
Pyrite (FeS_2)	17	4.99 g/cm ³
Barite (BaSO_4)	267	4.09 g/cm ³

Porosity and Lithology measurements

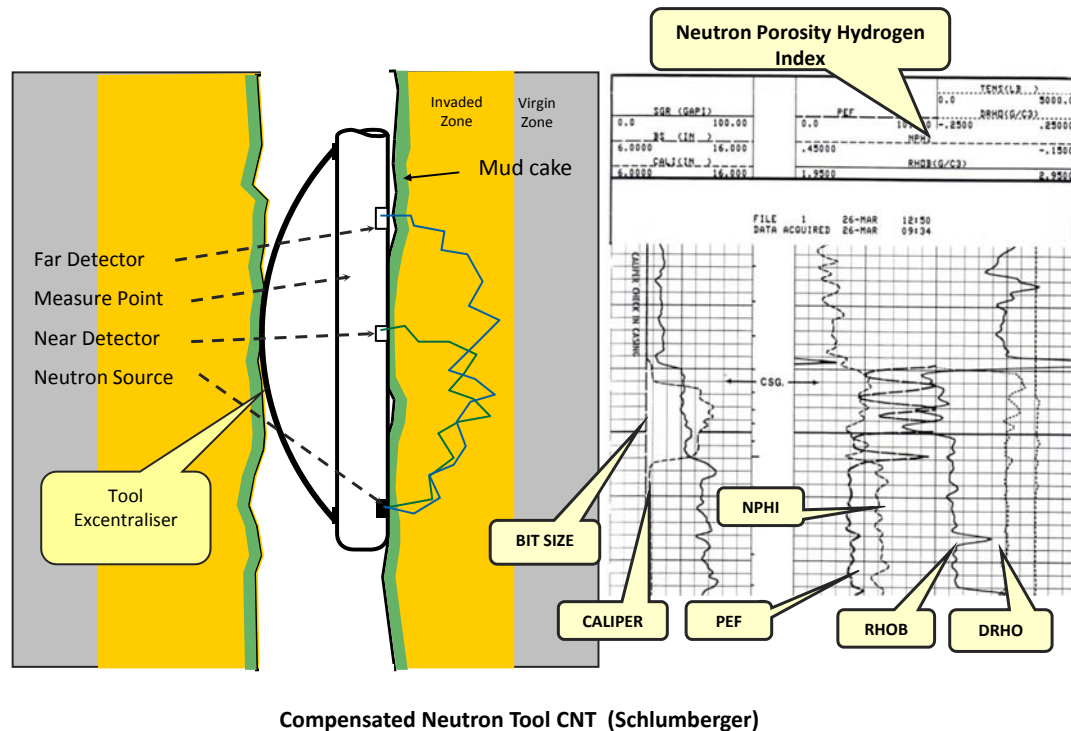
Neutron - Principle

► The Neutron tools emit high energy neutrons in the formation and counts low energy neutrons after collision with atoms from the formation

- A chemical radioactive source placed on the tool emits high energy neutrons in the formation.
- When neutrons collide with atoms, they are slowed down and lose their energy. Neutrons lose most of their energy when they **collide with hydrogen atoms** that have nearly the same mass.
- When the neutrons reach low (thermal) energy level, they are counted on 2 detectors placed above the source.
- The **Hydrogen Index** (HI) measurement is obtained from the ratio of neutron counts on the two detectors and is related to apparent water-filled porosity.
- The tool should be pressed against the borehole to minimize apparent porosity of the hole. HI measurement is sensitive to hole size (caves), temperature and salinity.

Porosity and Lithology measurements

Neutron - Principle



Porosity and Lithology measurements

Neutron NPHI

- ▶ The Neutron tools measure the Hydrogen Index HI of the formation
- ▶ The log is usually named **NPHI, Neutron Porosity Hydrogen Index**
- ▶ In porous water bearing reservoirs, it corresponds approximately to the amount of water or the porosity of the formation.
- ▶ But this is actually true only in clean fresh water bearing, because of the calibration of the neutron tools (after a Texas master well).
- ▶ Therefore, in **sandstone or dolomite reservoir**, a **correction** must be applied to the Hydrogen Index to obtain the reservoir porosity.
- ▶ Also, in oil or gas zones, the measurement is affected by the presence of hydrocarbons and must be **corrected**.

Sonic DT Measurement (BHC) - Principle

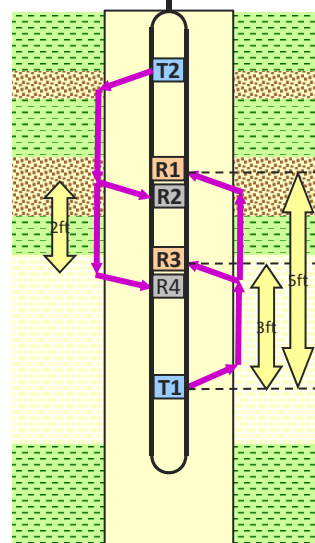
► Sonic log measures the time needed for a sonic wave to propagate over one feet of formation

- At time t_0 , a transmitter (T1) generates a short pressure pulse ($f=25$ kHz).
- This pulse moves through the mud, hits the borehole wall and, at a certain angle of incidence with the wall (the “critical angle”), it creates refracted sonic waves in the formation that move parallel to the wellbore.
- As these waves travel along the borehole wall, they create another compressional wave front in the mud column that will be detected by the tool receivers.
- Two receivers are used on the tool, which are spaced 3 ft and 5 ft from the transmitter (R3 & R1).
- The tool measures the time from t_0 to the first arrival detection at each receiver. The difference in the transit time is calculated, and then divided by the distance (2 feet) thus giving the “**slowness**” of the formation, in $\mu\text{s}/\text{ft}$ which is the inverse of the velocity of the sonic waves.
- DT is the **average of two slowness measurements**
 - We may access to DTc = compressional DT and/or DTs = shear DT obtained from the processing of refracted P waves or dipole sonic flexural waves

Porosity and Lithology measurements

Sonic DT Measurement (BHC)

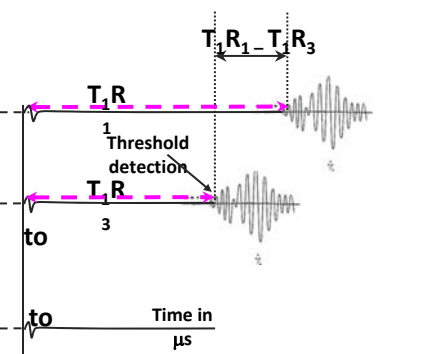
Scheme of the BoreHole Compensated Sonic BHC



When the tool is not centered or tilted, the relative transit times are off and there is an error with Δt .

To compensate for any error occurring when the tool is slightly tilted, two transmitters and four receivers are used.

This is called BHC measurement: borehole compensated sonic measurement.



$$\Delta t_{\mu\text{s}/\text{ft}} = \frac{(T_1R_1 - T_1R_3) + (T_2R_4 - T_2R_2)}{4}$$

= slowness \Rightarrow log DT

$$Velocity_{m/s} = \frac{304800}{\Delta t_{\mu\text{s}/\text{ft}}}$$

Porosity and Lithology measurements

Porosity from Sonic

► Formula

- Wyllie Formula (time averaged)

$$\Delta t_p = (1 - \Phi_u) \cdot \Delta t_{ma} + \Phi_u \cdot \Delta t_f$$

- In the case of clean formation ($V_{sh} = 0$)

$$\Phi_{u(S)} = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \times \frac{1}{B_{cp}} \quad \text{with compaction factor } 1 < B_{cp} < 1.6$$

- Raymer, Hunt & Gardner formula

$$\frac{1}{\Delta t} = \frac{(1 - \Phi_u)^2}{\Delta t_{ma}} + \frac{\Phi_u}{\Delta t_f}$$

- Simplified RHG formula (field observation)

$$\Phi_{u(SRHG)} = K \times \frac{\Delta t - \Delta t_{ma}}{\Delta t} \quad \text{with } K=0.700$$

Lithology	Sonic $\Delta t_{c_{ma}}$ ($\mu\text{s}/\text{ft}$)
Limestone (CaCO_3)	49
Dolomite (CaCO_3 , MgCO_3)	44
Sandstone (SiO_2)	56

Fluid	Sonic Δt_{c_f} ($\mu\text{s}/\text{ft}$)
Water	180-200
Oil	200-220
Gas	>250 (-> 500)

Porosity and Lithology measurements

Sonic - Applications

► DT log is an essential measurement for the geophysicist:

- Sound velocity in the geological formations
- Time–depth relationship (Time = f(Depth) and Time-Depth conversion)
- Comparison of Log and Seismic data
- Acoustic Impedance: $AI = \rho_{\text{hob}} \cdot \text{Velocity}$

► DT log may also be used to determine

- Porosity** in reservoir zones
- Lithology** (DT combined with Density or Neutron; DTc vs DTs)
- Rock mechanical properties** by combining density, DTc and DTs logs => useful for sanding prediction and wellbore stability

Pressure measurements and fluid sampling

RFT and MDT tools

► Old tools:

- RFT: Repeat Formation Tester (Schlumberger)
- SFT: Sampling Formation Tester (Halliburton Logging Services)
- FMT: Formation MultiTester (Baker)

► Today common tools are:

- MDT: Modular Formation Dynamic Tester (Schlumberger)
- RDT: Reservoir Description Tool (Halliburton LS)
- RCI: Reservoir Characterization Instrument RCI (Baker)

Repeat Formation Tester



MDT tool



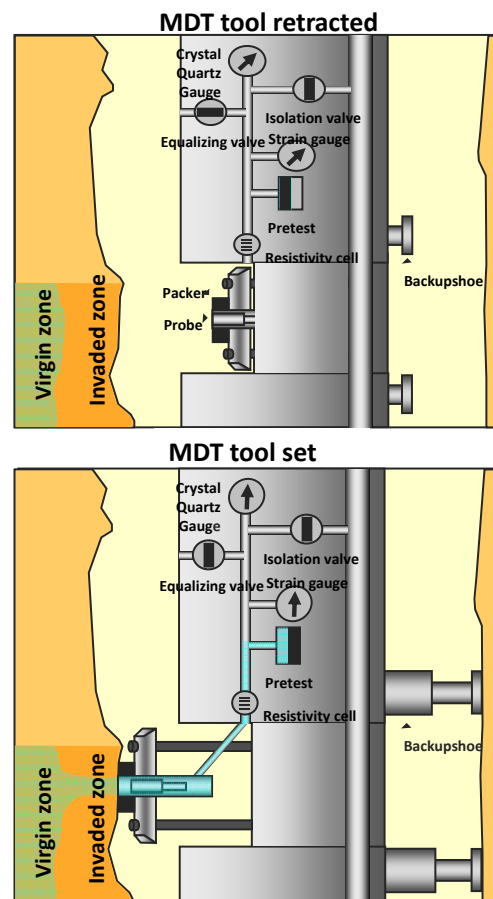
Pressure measurements and fluid sampling

MDT operation

► MDT tool shown in closed and open position for pressure test measurement.

► Inside the tool:

- 2 gauges: Strain and Hewlett Packard pressure gauges.
- The resistivity cell measurement on the flow line can be used to differentiate water or oil from mud filtrate.
- The pretest chamber volume can be selected by software, depending on the permeability of the formation.

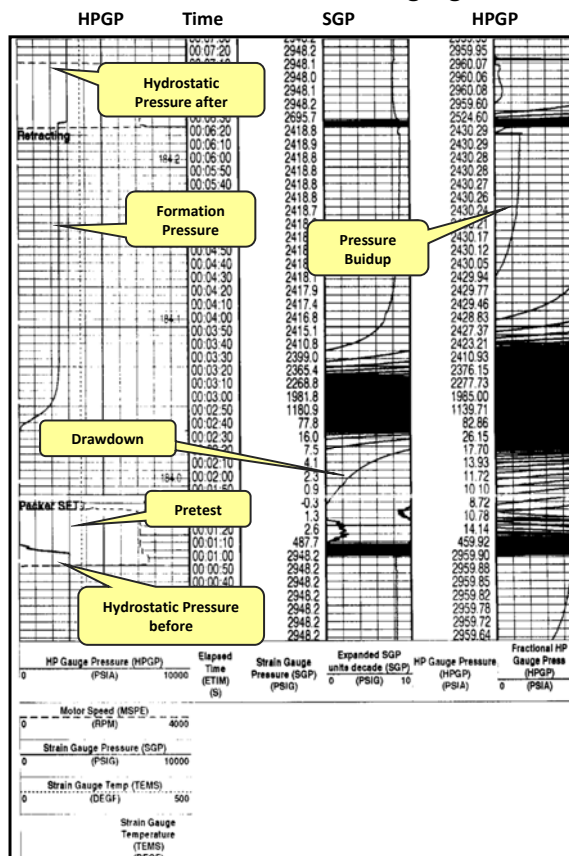


(from Schlumberger)

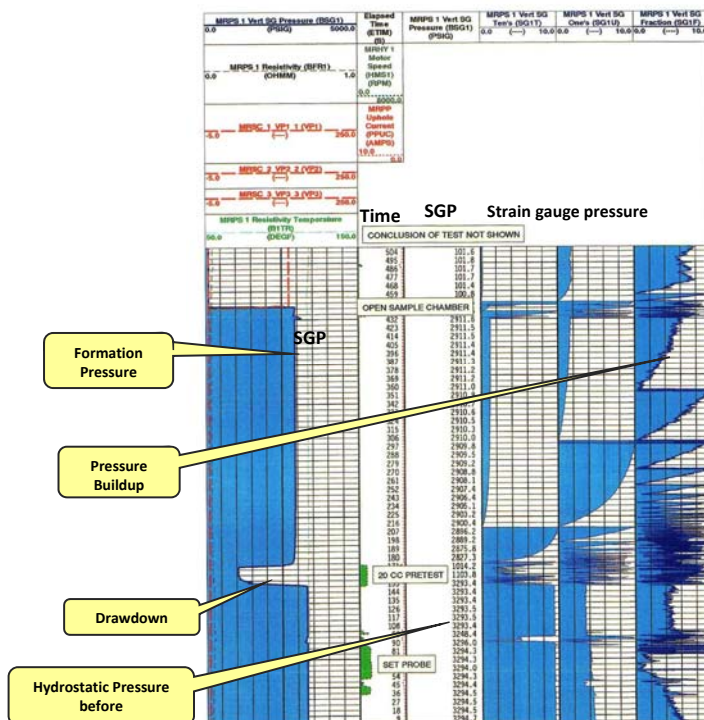
Pressure measurements and fluid sampling

MDT: Pressure Test Records

Pressure Record with SGP and HP gauges

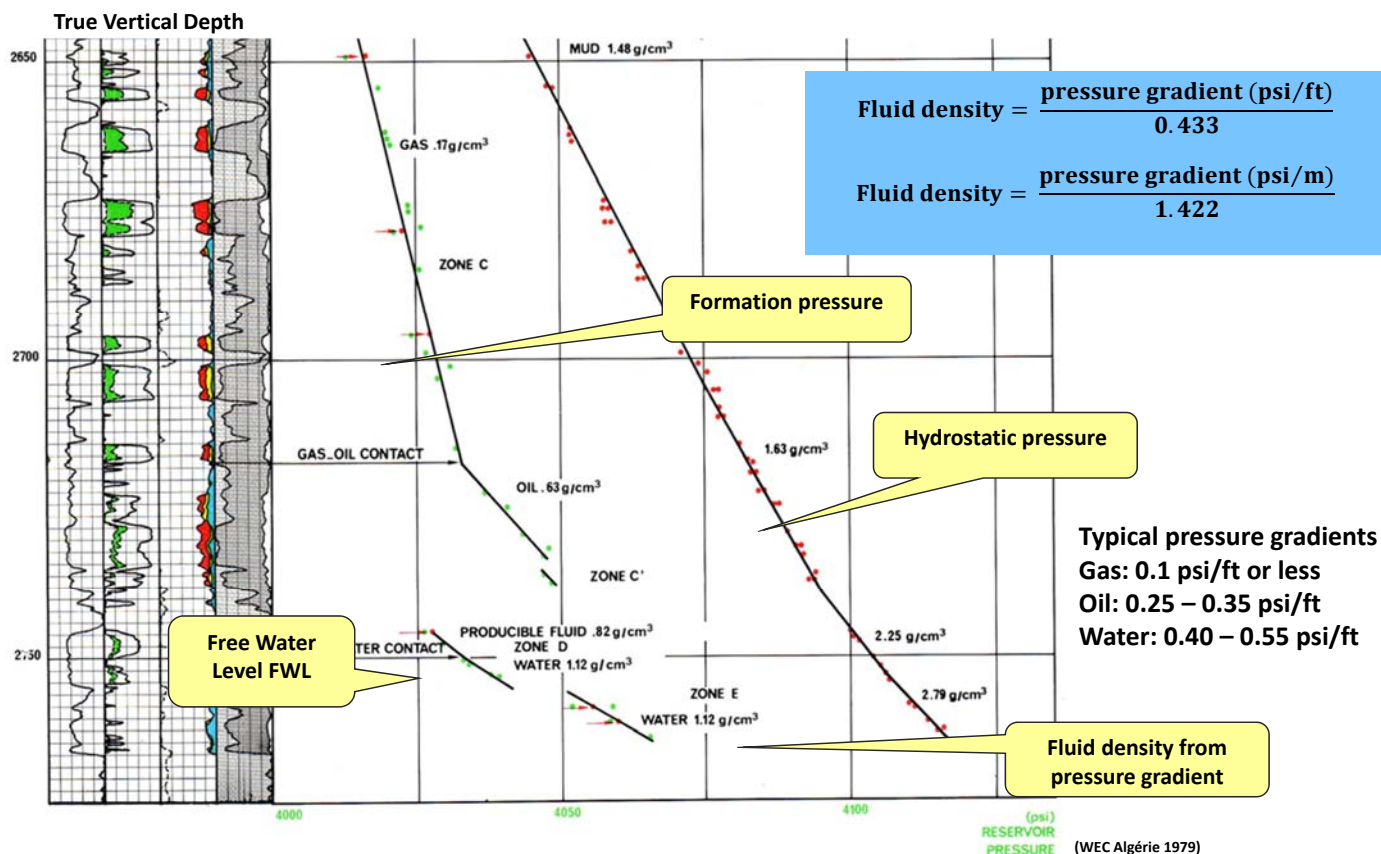


Pressure Record with SGP gauge



Pressure measurements and fluid sampling

Pressure gradients and fluid density



Applications of MDT log

► MDT log may be used to

- Measure the **formation pressure**
- Estimate the **reservoir permeability** from interpretation of pressure variation
 - During short production period: drawdown
 - During non-production period: build-up (cf. Horner plot)
 - To be compared with NMR permeability
- Determine the **fluid contacts**
 - To be compared with resistivity/induction logs
- Evaluate the **pressure gradients** and **fluid densities**
- **Sample** formation fluids
- **Perform basic PVT analysis**
 - Nowadays, first basic PVT analysis are performed directly downhole!
- Others
 - Detecting lateral or vertical permeability barriers
 - Identifying multiple reservoirs (for example two independent oil reservoirs)

Permeability logs

Permeability, logs and NMR

► Permeability is of paramount importance for reservoir characterization , modeling and engineering

- Permeability can be accessed through core analysis but measurement is long, expensive and values are discrete and uncertain (is the sample representative? Do we take heterogeneities into account?)
- One of the main objectives of wireline logging is to obtain a continuous permeability log
 - In-situ measurement ensuring good representativity
 - It gives access to vertical profile of permeability

► Permeability logs

- Getting a direct permeability indicator, especially from acoustic response => Sonic log
- Deriving permeability from porosity and indicators related to pore-geometry => NMR log

► NMR logs give excellent results for sandstones formation

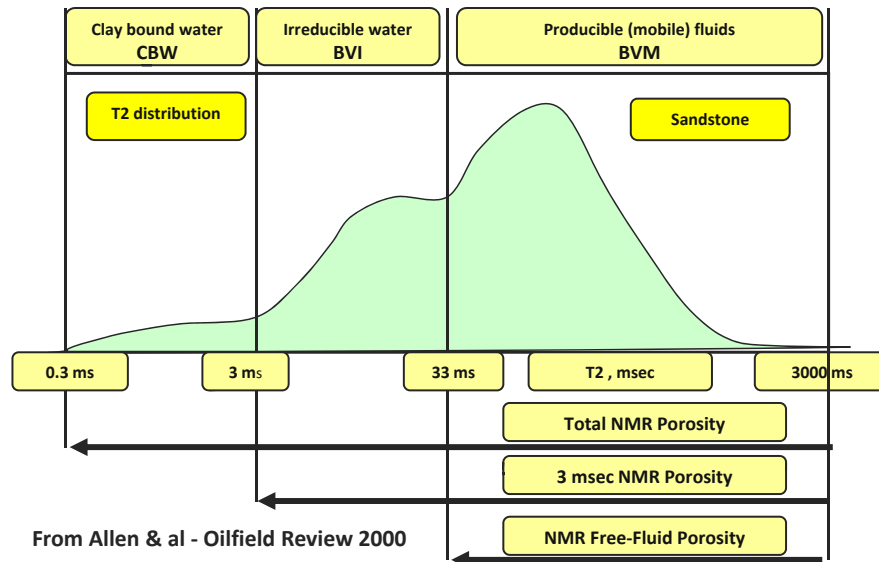
- In complex carbonate formations, NMR logs may fail but a solution would be to use information from continuous electrical imaging at the borehole combined with conventional porosity logs to build permeability indicators

Permeability logs

Permeability from NMR – Reminders (1)

► Principle

- NMR gives information about the transverse relaxation time T_2 of protons (i.e. hydrogen atom nuclei) reacting to interference with strong magnetic field
- The distribution of T_2 provides information about total porosity through the distribution of pore size but also about Bound Volume Index and Free Fluid Index
- Using these index, it is possible to access to permeability



Open Hole Well Logging and Interpretation

Permeability logs

Permeability from NMR – Reminders (2)

► Two correlations models are used

► Free-fluid model or Coates model or Timur-Coates model

$$k_{TIM} = C \cdot \phi^m \cdot (FFI/BVI)^n$$

where FFI and BVI are respectively Free Fluid Index and Bound Volume Index and C is a formation-dependent parameter and m and n are constants, generally $m = n = 2$

► Schlumberger-Doll-Research (SDR) or Mean- T_2 model

$$k_{SDR} = C \cdot \phi^m \cdot (T_{2LM})^n$$

where T_{2LM} is the logarithmic mean of relaxation times T_2 and C is a formation-dependent parameter e.g. 4 for sandstones and 0.1 for carbonates and m and n are constants, generally $m = n = 2$

Permeability logs

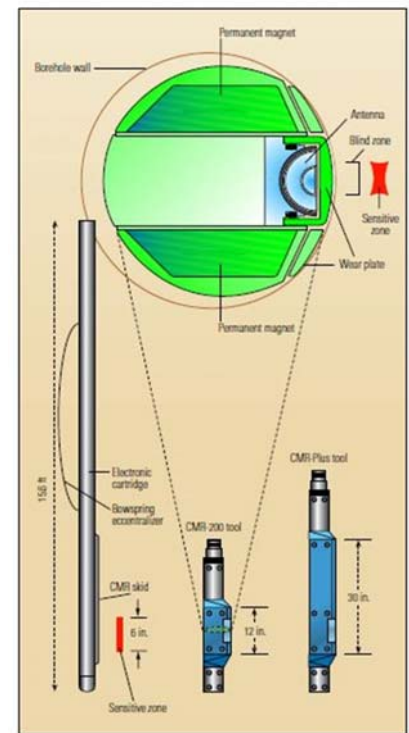
NMR logging tools

► History

- First NMR logging tools appeared in the 1960's developed by Chevron and later on by Schlumberger
- But the first tools did not control the volume of investigation and read borehole fluids => the mud had to be treated to reduce its contribution to the signal
- In 1990 the MRIL (Magnetic Resonance Imager now marketed by Halliburton) appeared and in 1995 the CMR (Combinable Magnetic Resonance) tool was created by Schlumberger
 - Using powerful permanent magnets allowing to control the measurement volume and avoiding the mud doping
 - Using sequences of pulse to improve the quality of the signal

► Use

- NMR logs are generally calibrated over a given interval of interest and confronted to core data for validation



From Allen & al - Oilfield Review 2000
CMR tool design with two permanent magnets creating the resonant-field sensitive zone in the formation

Permeability logs

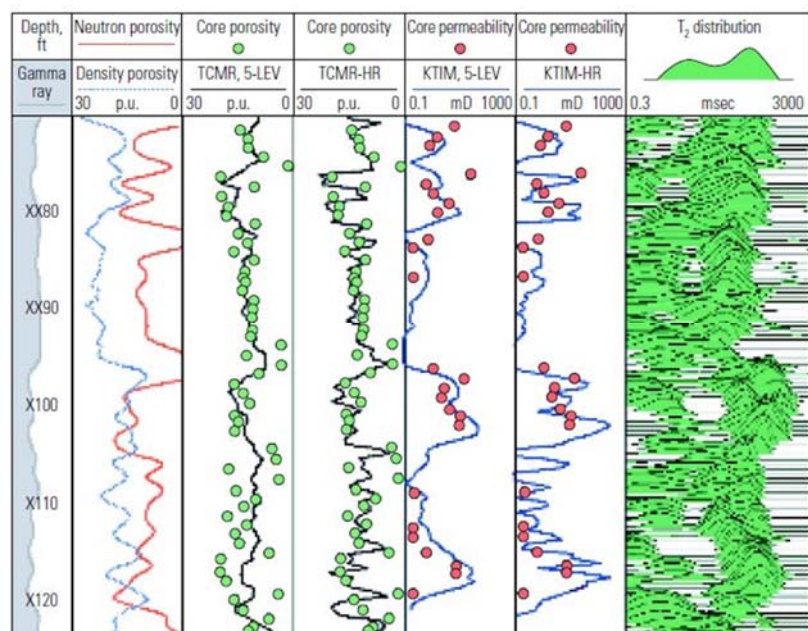
NMR logs and Reservoir Engineering

► NMR logs give access to

- The vertical permeability profile along the wells
 - Allowing to determine permeability variations and especially high permeability zones => **productivity**
- The vertical total porosity profile but also BVI and BVM (i.e. free-fluid volume and hence immobile-fluid volume)
 - Allowing to identify intervals where fluid may be mobile or immobile => **productivity of a given fluid**

► NMR logs often used in combination with MDT

- Optimizing MDT design by identifying most productive zone
- Confirming fluids contacts from MDT



From Allen & al - Oilfield Review 2000

Comparison of total porosity and permeability from NMR classic and high-resolution log to core data

Logging tools summary

Log	Measured phenomena	Radius of investigation	Vertical resolution	Applications	Limitations
Caliper	Well-bore diameter Logs: CALI	none	none	Identification of caves, fractures; Borehole roughness Presence of mud cake i.e. reservoir zone	
GR	Natural radioactivity Logs: GR, SGR, CGR	12 ''	2 ft	Identification of shaly formations (seals) and reservoirs Shale content	Sensitive to changes of hole size
Spontaneous Potential	Difference of potential between electrode in the well and at surface Logs: SP	none	6 to 10 ft	Identification of shaly formations and reservoirs Shale content Water resistivity R_w	WBM only

Logging tools summary

Log	Measured phenomena (borehole, formation or fluid)	Radius of Investigation	Vertical resolution	Applications	Limitations
Resistivity	Conductivity / Resistivity of formations (rocks & fluids) through induced currents and voltage Logs: LLD, LLS	16 to 45'	2 ft	Identification of water-oil contact Water resistivity R_w Water and hydrocarbon saturation S_w and S_{hc}	WBM only Low values of R_m , R_{mf} and R_{xo}
Micro-resistivity	Same Logs: MSFL, MCL, MLL,...	1 to 4''	2 to 3''	Identification of water-oil contact Mud filtrate resistivity R_{mf} Residual oil saturation S_{xo}	WBM only Low values of R_m , R_{mf} and R_{xo}
Induction	Formation resistivity through induced Foucault currents and magnetic fields Logs: ILD, ILM, AH90, AH60, AH30, etc.	16 to 65''	2,5 to 3 ft	Identification of water-oil contact Water resistivity R_w Water and hydrocarbon saturation S_w and S_{hc}	Resistivity < 200 – 250 $\Omega.m$ $R_{xo}/R_t > 2$

Logging tools summary

Log	Measured phenomena (borehole, formation or fluid)	Radius of Investigation	Vertical resolution	Applications	Limitations
Neutron	Hydrogen Index measured through counting de-energized neutrons returning from the formation Log: NPHI	10"	2 ft	Identification of gas-oil contact Estimate porosity together with Density log	Sensitive to environment of the borehole
Litho-Density	Density and Photo-Electric Factor (PEF) measured through counting low energy Gamma Rays returning from formation Logs: RHOB, PEF	8"	18"	Lithology and density RHOB estimates porosity together with Neutron log	Sensitive to environment of the borehole
Sonic	Slowness/velocity of acoustic waves, compressional/shear waves obtained through pressure pulses in the mud Logs: DT, DTc, DTs	6"	2 ft	Porosity Time-depth conversion Mechanical properties of the formation	Sensitive to variation of compressibility

Open Hole Well Logging and Interpretation

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Logging tools summary

Log	Measured phenomena (borehole, formation or fluid)	Radius of Investigation	Vertical resolution	Applications	Limitations
Nuclear Magnetic Resonance (CMR)	Transverse relaxation time T_2 of protons (i.e. hydrogen atoms nuclei) reacting to interference with strong magnetic field Log: NMR-k, NMR-porosity, NMR-3ms porosity, ...	1"	6"	Vertical profile of total porosity (but also free-fluid volume) Vertical profile of permeability	Minimum 6,5" wellbore for CMR

Open Hole Well Logging and Interpretation

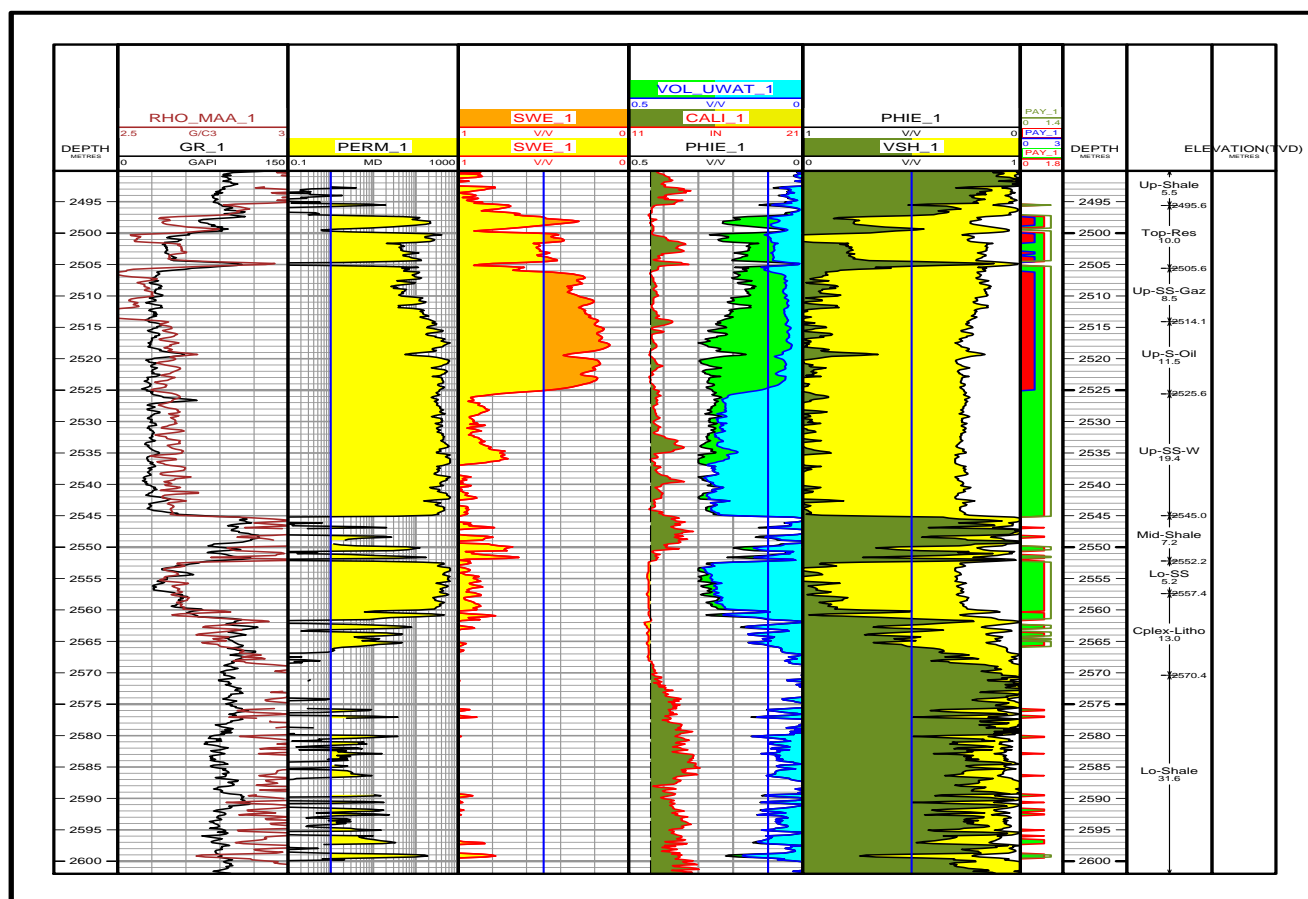
IFP Training | 249



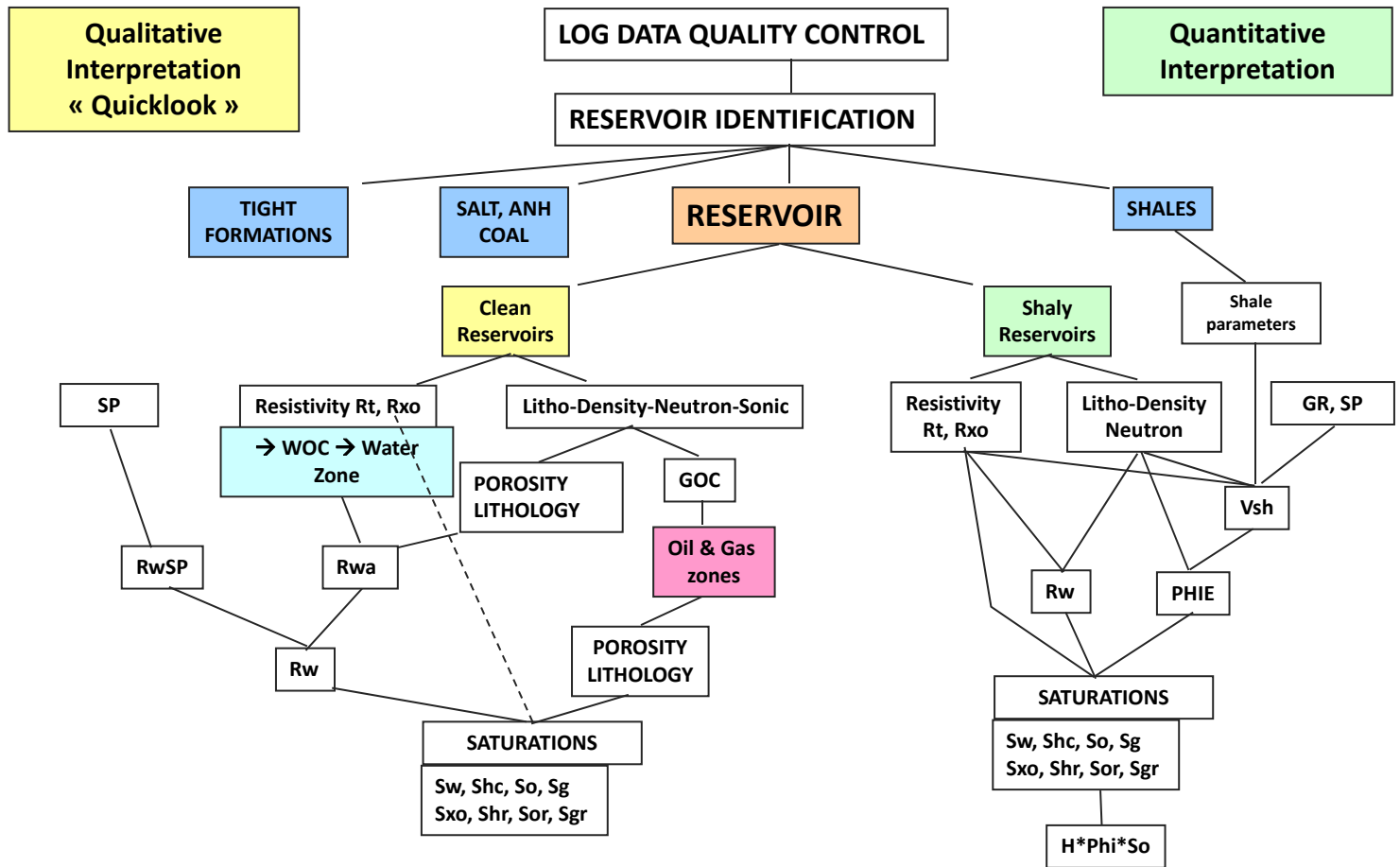
- ▶ **Logging records allow to collect detailed data around the well**
 - Various depths of investigation : data “near” and “far” from the wellbore
 - Various vertical resolutions
- ▶ **Interpretation of well logging records**
 - Identification of reservoir (and non-reservoir) formation
 - Identification of fluids (water, oil, gas) and contacts
 - Estimate of porosity and fluid saturations
 - Comparison with laboratory data (petrophysics)
- ▶ **Correlation between wells**
 - Correlation of key surface through the basin
 - Combination with seismic data

Log Interpretation Methodology

Example of log



Qualitative and quantitative log interpretation



Log interpretation methodology

Qualitative and quantitative log interpretation

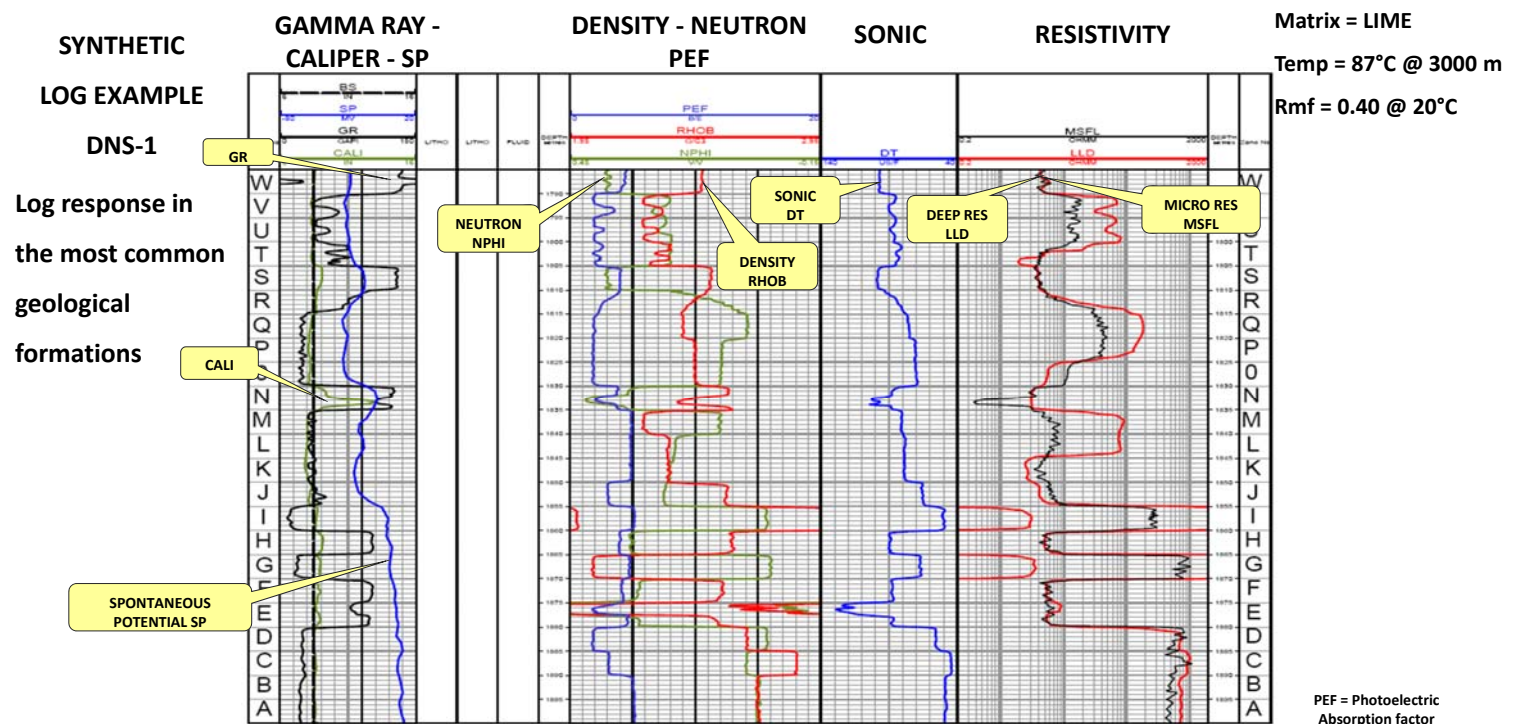
► Procedure

1. Log Interpretation starts with **LQC** – confirmation that the logs are of good quality.
2. The **identification of potential reservoirs** comes next. This is done by first eliminating tight formations, shales, and any other beds such as salt, coal and anhydrite that cannot be reservoirs. We are left with potential reservoir zones to study further.
3. Some of these potential reservoirs will be clean, that is clay and shale free. These reservoirs, where there is essentially just one type of rock mineral, can be interpreted with a **qualitative** “Quicklook” method.
4. Other reservoir rocks will contain shales or other minerals which require more in-depth analysis, or a **quantitative** interpretation.
5. The quantitative interpretation involves analyzing clay parameters, the volumes of clay and other minerals, and correcting the values of porosity for these effects.
6. Analysis of the “clean” formations (process described on the left part of the scheme in the previous slide).
 - Porosity logs will define the porosity, find the GOC, and help determine R_w .
 - Resistivity logs allow to find the WOC and also determine R_w .
 - Both porosity and resistivity curves are used to determine the saturations (water then HC)
 - Finally, the thickness of the hydrocarbon zone H , the average porosity ϕ , and average hydrocarbon saturation S_o are determined so as to calculate $H \cdot \phi \cdot S_o$.

Quick-look qualitative log interpretation - Objectives

- Identification of non-reservoir zones
- Delineation of reservoirs
- Identification of Water-Hydrocarbon contacts (WOC / WGC)
- Identification of Gas-Oil contact in HC-bearing zones
- Determination of the lithology and the porosity in the different zones
- Determination of the formation water Resistivity (R_w)
- Estimation of both water and hydrocarbon saturations in HC zones

Log response in common geological formations



Well DNS1 is made up of synthetic log curves including:

Track 1 - GR, Caliper, Bit size and SP

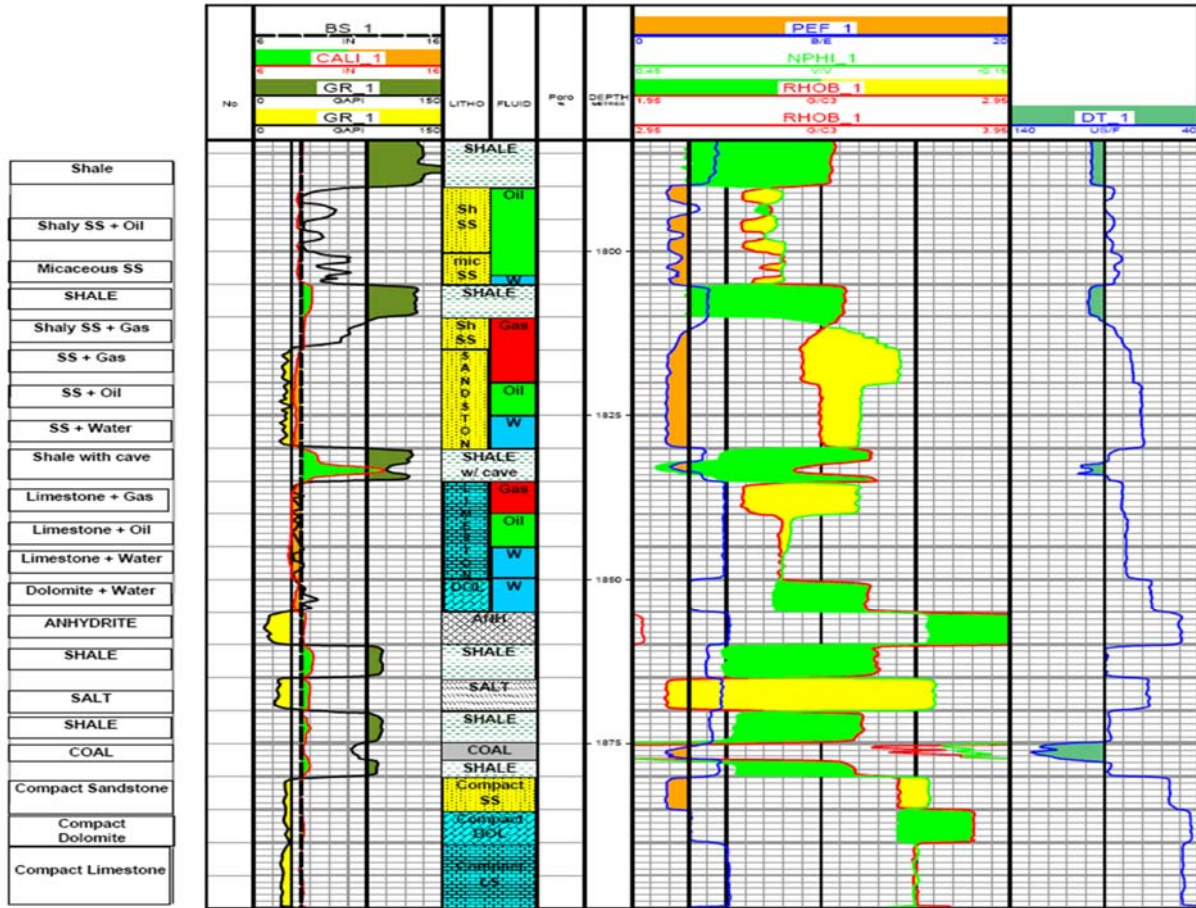
Track 2 - Pef, RHOB, NPHI

Track 3 - Dt

Track 4 - LLD, MSFL

The log is made up of a series of geological horizons or beds of various lithologies, porosities, fluids and saturations. In this short section of hole, most of the log responses discovered in the fields are presented.

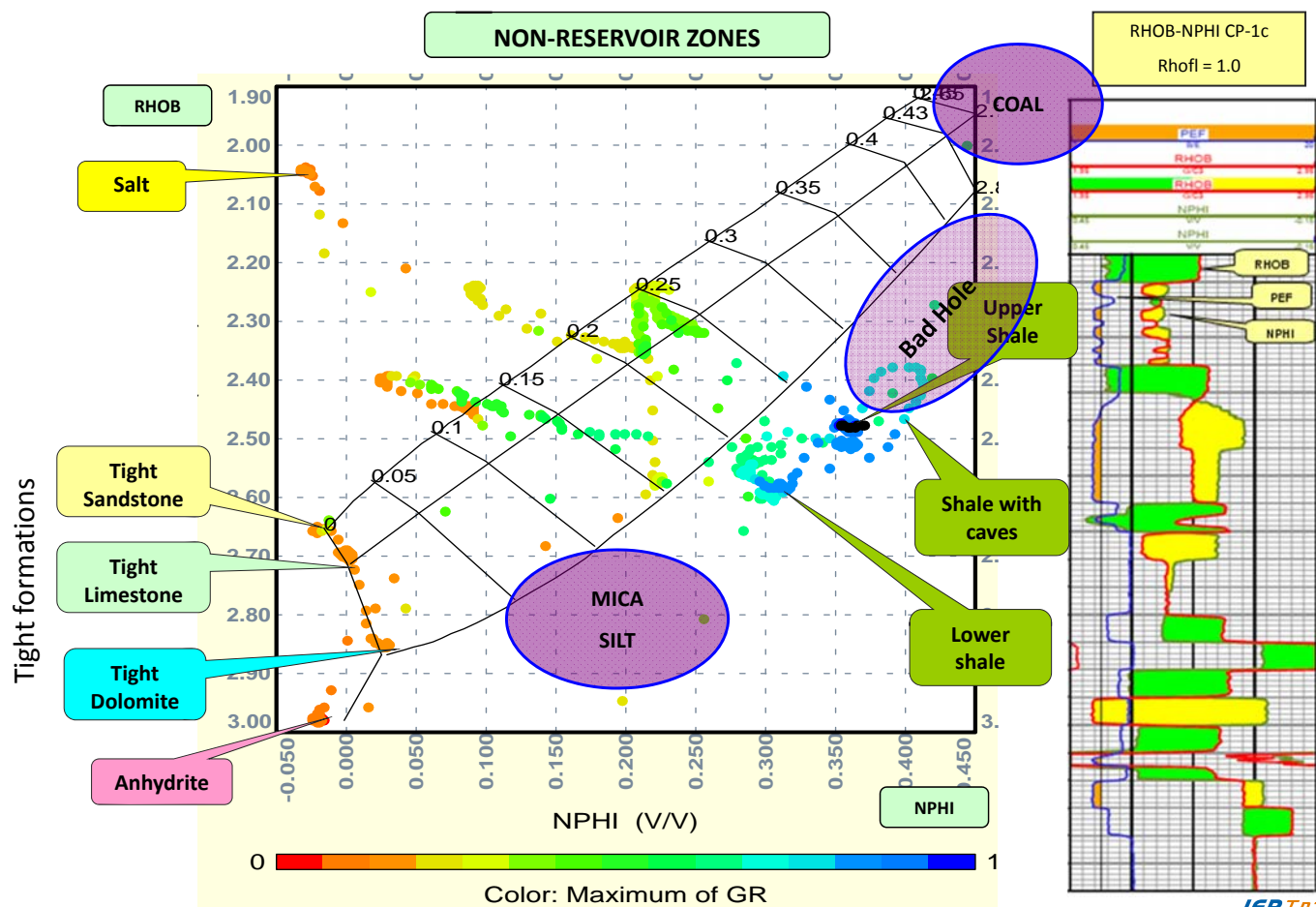
Quick-look solution (example)



Average quick-look values for common lithologies

ZONE	Depth	Depth	Lithology	Zone	Temp	Rmf	SSP	ZONE	GR	RHOB	NPHI	PEF	DT	Poro
	zoning	select		W/O/G										DN
	m	m			C		mV		API	g/c3	%		us/ft	%
	1785				59				135	2,47	36	4,5	97	
W	1790	1789	Shale					W	37	2,25	21	2	85	
V	1795	1793,5	Shaly Sandstone	O	59			V	60	2,27	22	2	89	24%
U	1800	1796	Shaly Sandstone	O	59	0,176		U	45	2,27	21	2	85	25%
T	1805	1801	Micaceous SS	W				T	50	2,30	21	2	85	21%
S	1810	1808	Shale					S	130	2,30	36	4	100	24%
R	1815	1813	Shaly Sandstone	G				R	70	2,50	9	2,5	80	
Q	1820	1818	Sandstone	G				Q	25	2,40	3	2	75	15%
P	1825	1823	Sandstone	O	60	0,176		P	25	2,40	9	2	70	12%
O	1830	1828	Sandstone	W				O	25	2,45	9	2	70	12%
N	1835	1833	Shale					N	110	2,40	40	2	100	
M	1840	1838	Limestone	G	60	0,2		M	30	2,25	9	5	80	23%
L	1845	1843	Limestone	O	60	0,2		L	30	2,35	20	5	80	21%
K	1850	1848	Limestone	W	60	0,2	-20	K	30	2,36	21	5	80	21%
J	1855	1853	Dolomite	W				J	45	2,57	22	3	65	15%
I	1860	1858	ANHYDRITE					I	13	2,97	-2	5	50	0%
H	1865	1863	Shale					H	100	2,60	30	4	90	
G	1870	1868	SALT		60	0,176		G	16	2,04	-3	5	67	0%
F	1875	1873	Shale					F	100	2,55	28	4	89	
E	1880	1876	COAL					E	75	1,57	54	2	129	
D	1885	1883	Compact Sandstone (Quartzite)					D	25	2,65	-2	2	56	0%
C	1890	1888	Compact Dolomite					C	27	2,85	3	3	44	0%
B	1895	1893	Compact Limestone					B	24	2,70	0	5	49	0%
A	1900	1898	Compact Limestone		61			A	24	2,70	0	5	49	0%

Density-Neutron crossplot (NPHI) - 1/2

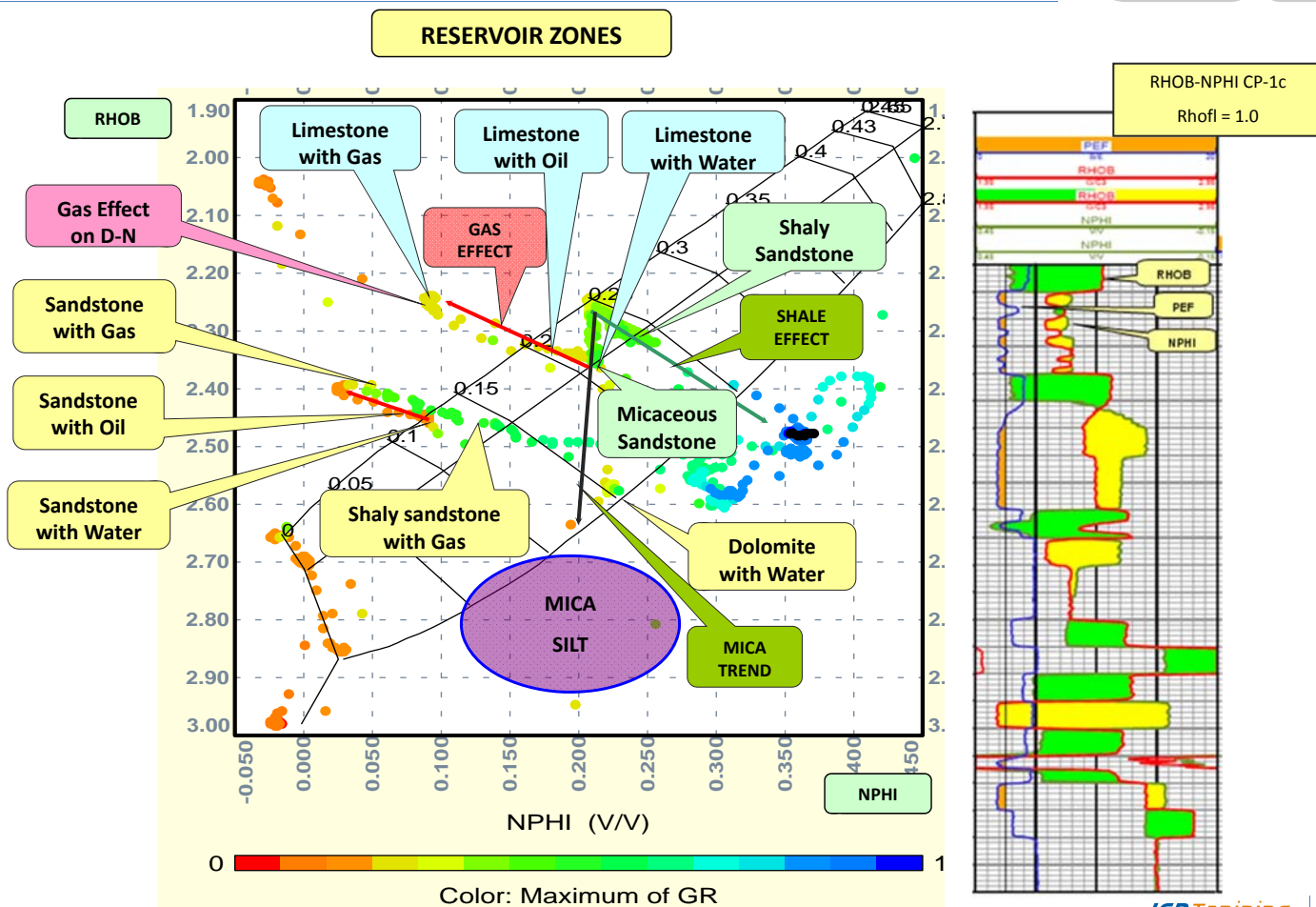


Open Hole Well Logging and Interpretation

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Density-Neutron crossplot (NPHI) - 2/2



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Quick-look: non-reservoir identification 1/5

- ▶ **Case of a well drilled with water-based mud and with R_t and R_{xo} available**
- ▶ **Identification of reservoirs and non-reservoir intervals**
 - Elimination of shale, tight formations, salt, anhydrite, coal...
- ▶ **First check D-N scales for **matrix compatibility****
- ▶ **Identification of **shales** (log values listed below are average values)**
 - Caliper: **caves**
 - GR: **high values** (> 70)
 - Deep, Shallow, and Micro Resistivity or Array Induction logs: **low resistivities** (< 20)
 - logs close to each other
 - Neutron values (NPHI or TNPH): **high values** ($> 30\%$)
 - Separation between neutron and density (with Neutron left of Density)
 - SP: **flat**, fairly constant in thick shale layers
 - Defines **shale baseline**

Quick-look: non-reservoir identification 2/5

- ▶ **Case of a well drilled with water-based mud with R_t and R_{xo} available**
- ▶ **Identification of tight formations (limestone, sandstone, dolomite - not fractured)**
 - Caliper: **close to BS**
 - GR: **low values** (< 30)
 - Deep, Shallow, Micro-resistivity or Array Induction : **high values** (> 200)
 - logs close to each others
 - Density, Neutron, Sonic: close to matrix reference values
 - Neutron: **low** ($< 5\%$)
 - Sonic: **low** (< 60)
 - Density: **high** (> 2.60)
 - SP: **flat** (similar to shale)

Quick-look: non-reservoir identification 3/5

- ▶ **Case of a well drilled with water-based mud and with R_t and R_{xo} available**
- ▶ **Identification of specific lithologies (salt, anhydrite)**
 - Caliper: **close to BS** but caving (can be observed in salt)
 - GR: **low values** (< 30)
 - Deep, Shallow, Micro-resistivity or Array Induction: **high values** (> 500)
 - logs should be close to each others (but can also be apart...)
 - Density-Neutron-Sonic: see table in appendix for reference values
- ▶ **Identification of coal beds**
 - GR: **low values** (but sometimes can be as high as in shales)
 - Neutron: **high values** (> 30 %)
 - Density: **low value** (< 2.0 g/cc)
 - Sonic: usually **high value** (> 90 ms/ft)
 - Resistivity: **low**, close to shale (but can also be high sometimes)

Quick-look: Water zone 4/5

- ▶ **Water-Oil contact identification**
 - Determination of WOC in a reservoir
 - With the resistivity overlay technique (R_t - R_{xo})
- ▶ **In the water zone**
 - Determination of the lithology and the quick-look porosity
 - from Density-Neutron
 - Determination of R_w
 - from R_t and apparent D-N porosity
- ▶ **Saturations: Archie's formula**
 - In the HC zone
 - In the oil zone
 - In the gas zone

$$R_t = \frac{R_o}{S_w^n} = \frac{a}{\Phi^m} \cdot \frac{R_w}{S_w^n} = F \cdot \frac{R_w}{S_w^n} \Rightarrow S_w = \sqrt[n]{F \cdot \frac{R_w}{R_t}}$$

Quick-look: hydrocarbon zone 5/5

► In the hydrocarbon zone

- Identification of Gas-Oil contact using D-N
 - so-called gas effect on Neutron log

► In the oil zone

- Determination of the lithology and the Quick-look porosity
- Calculation of S_w and S_{hc} , S_{xo} and S_{hr}

► In the gas zone

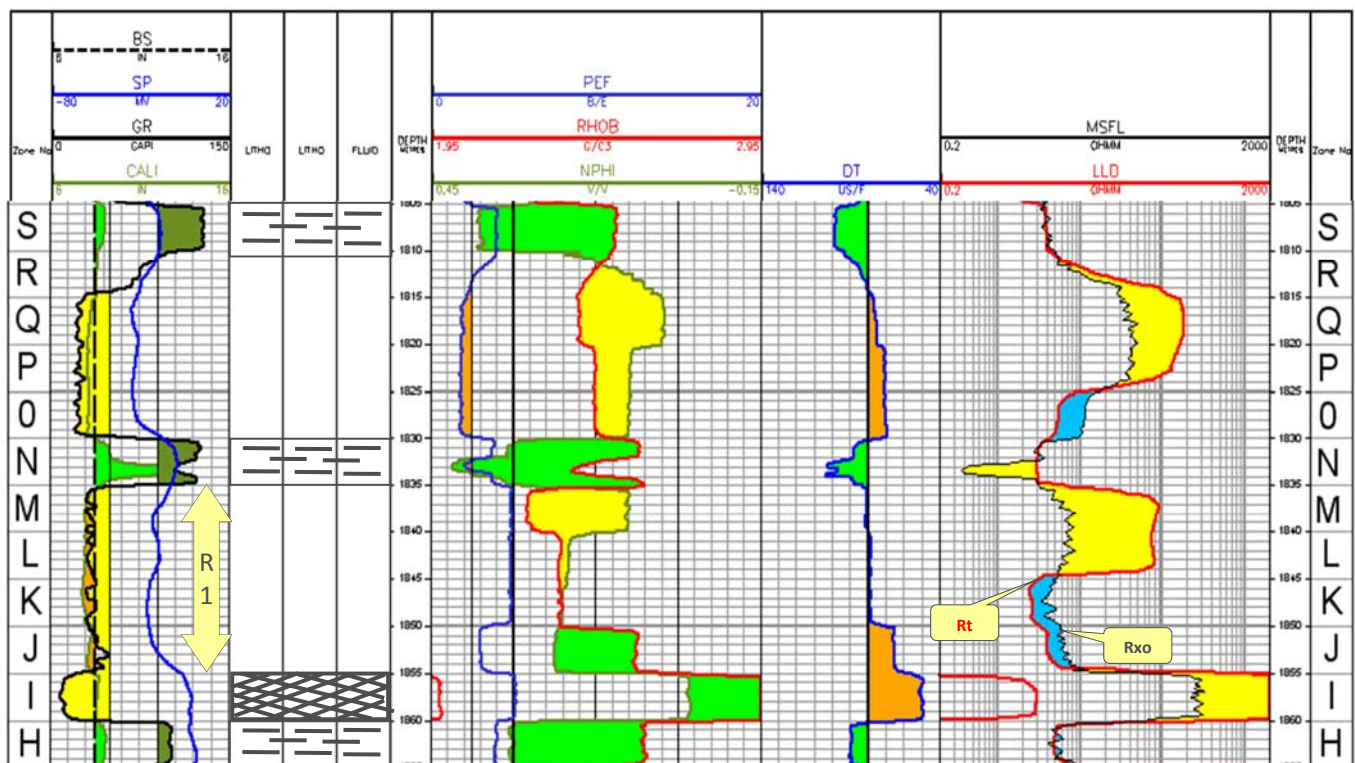
- Determination of the lithology and the Quick-look porosity
- Calculation of S_w and S_{hc} , S_{xo} and S_{hr}

► Density-Neutron crossplot

- Check the lithology and the porosity for points in water, oil and gas zones

Log interpretation methodology

DNS-1: Quick-look of reservoir-1: fluid contacts



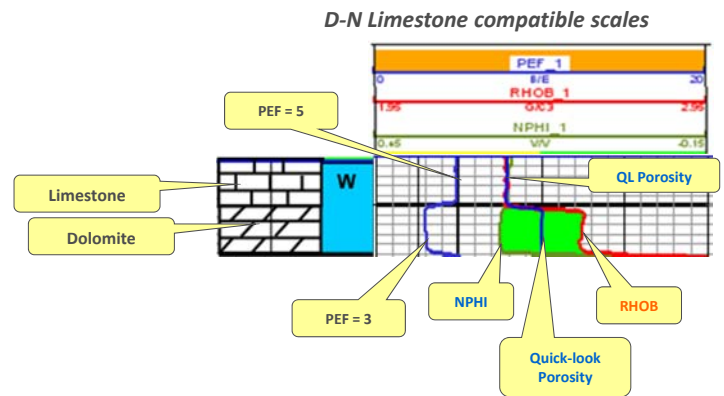
Determination of lithology, porosity in clean water zones

► Verification of D-N scales for matrix compatibility

- Case of Limestone compatible scale

► Quicklook Lithology

- Determination using the respective position of Density-Neutron curves
- Confirmation of lithology with the PEF log, if available and valid



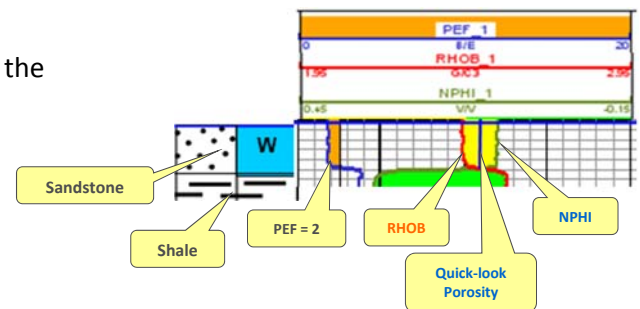
► Quicklook Porosity

- Reading on the Neutron scale of the value corresponding to the middle of the D-N separation
- Water Zone:

$$\Phi_u = \frac{\Phi_N^{ma} + \Phi_D^{ma}}{2}$$

$$\Phi_D^{ma} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

[ma = Limestone matrix ($\rho_{ma} = 2.71$, $\phi_{Nma} = 0$)]



Determination of HC type, lithology, porosity in clean HC zone

► Gas-Oil contact and Hydrocarbon type

- Separation between Density and Neutron logs → GOC → Oil and Gas zones

► Quicklook Lithology

- Oil zone:
 - Determination using the respective position of D-N curves
 - Confirmation of the lithology with the PEF log, if available and valid.
- Gas zone:
 - Use PEF, if available and valid
 - See mud log or core description

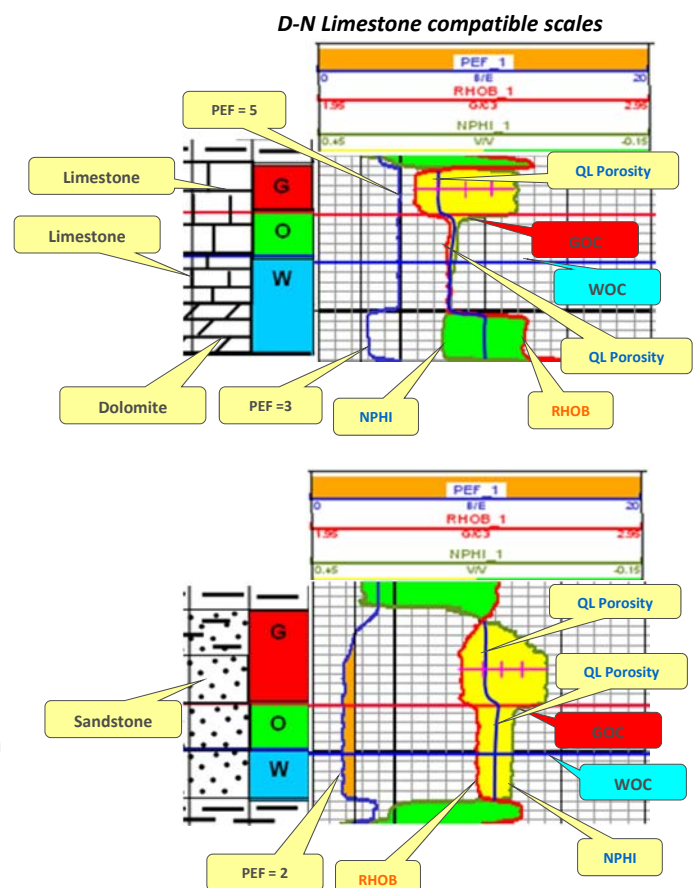
► Quicklook Porosity

- Oil zone: reading on the Neutron scale, the value corresponding to the middle of the D-N separation
- Gas zone: reading at the quarter of D-N separation, on the density side

$$\Phi_u = \frac{\Phi_N^{ma} + \Phi_D^{ma}}{2}$$

$$\Phi_u = \frac{\Phi_N^{ma} + 3\Phi_D^{ma}}{4}$$

[ma = Limestone matrix ($\rho_{ma} = 2.71$, $\phi_{Nma} = 0$)]



Water and hydrocarbon saturation

1 – Determination of WOC (Overlay Technique)

2 – Determination of Lithology in the water zone

3 – Determination of GOC

4 – Determination of Lithology in the HC zone

5 – Determination of Porosity in water, oil, gas zones

6 – Thickness of water, oil, gas zones

Case of vertical well drilled with Water Based Mud

7 – Determination of R_w in the water zone (R_w -Ratio, R_{wa})

8 – Determination of Saturation in oil and gas zones

0.45 NPHI 0.0 -0.15

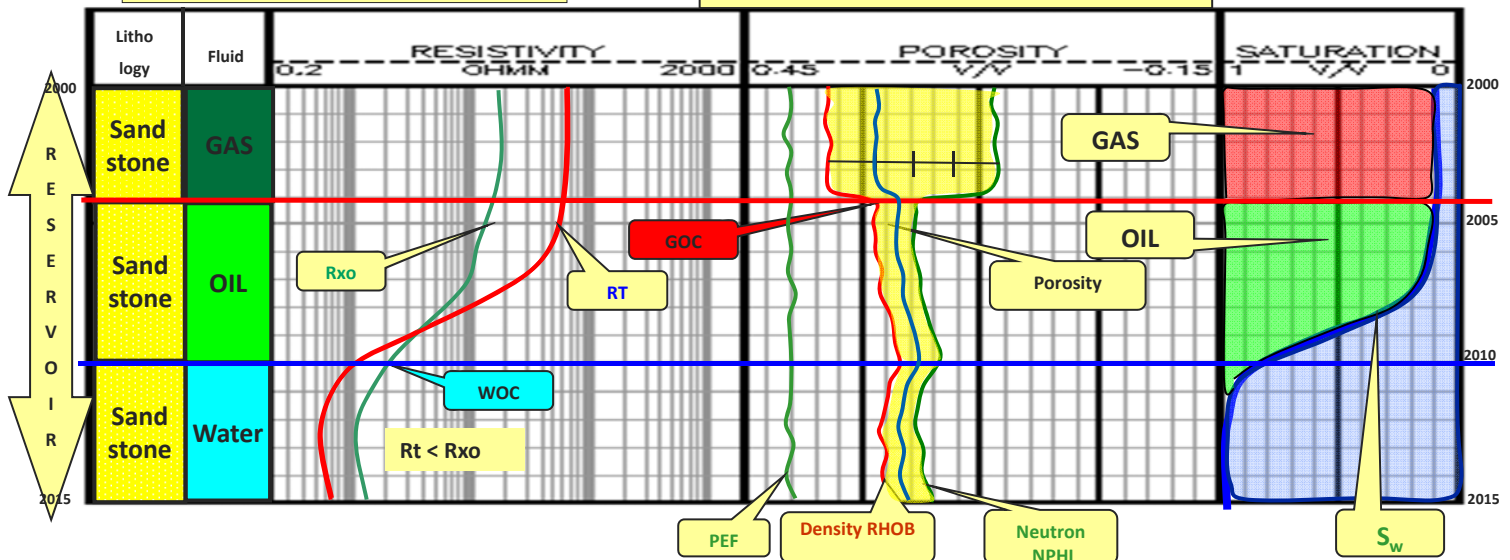
1.95 RHOB 2.70 2.95

0 PEF 20

Matrix = LIME

Temp = 70 °C

$R_{mf} = 0.2 \Omega m$ at 20 °C



The water and gas saturations can be computed the same way as in the oil zone.

The water saturation is reported here on the right of the logs. This is what we call a water saturation profile showing variation of 100% to 9% in the oil and gas zone.

Hydrocarbons in place

► Hydrocarbons at the well

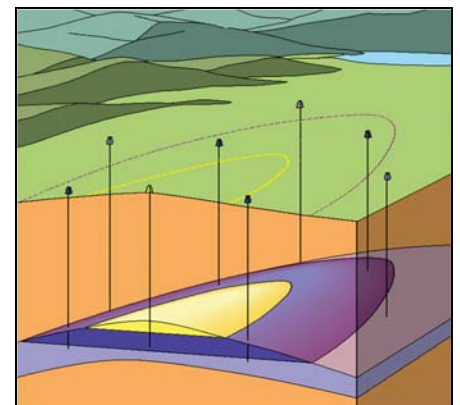
- Nature, boundaries and proportions of fluids in-place
- Net thickness and effective porosity of reservoir levels
- Hydrocarbon leg at the well = Net thickness $\times \Phi \times S_{hc}$

► Hydrocarbons in the structure (at field scale)

- Volume of hydrocarbons in place: OOIP, OGIP, OHIP, HIIP (MMm³, MM barrels)
- Impregnated area at the WOC (or ODT): A (km²)

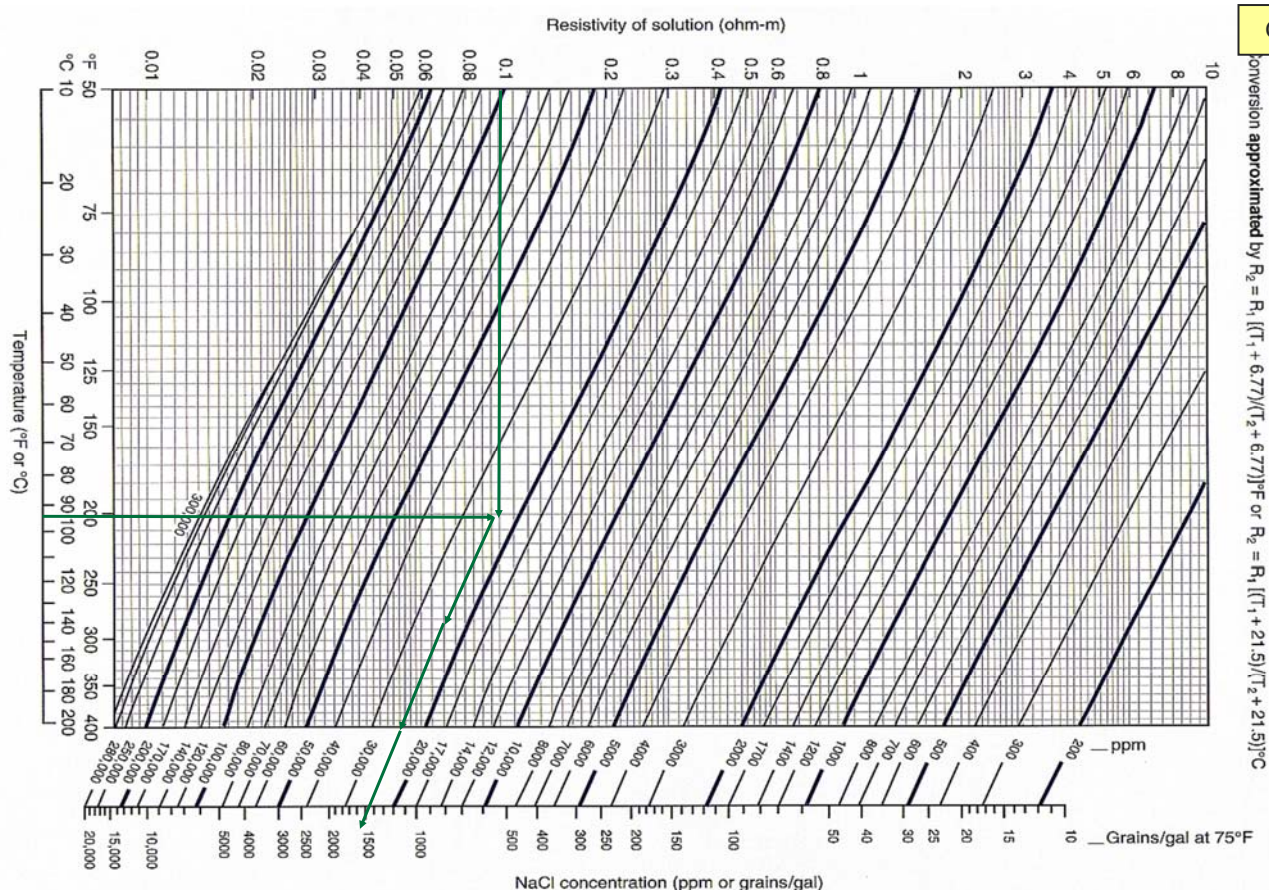
► Impregnated volume (HIIP)

- $HIIP = A \cdot h \cdot N/G \cdot \Phi \cdot S_{hc}$



Charts and tables

Water Resistivity and Water Salinity

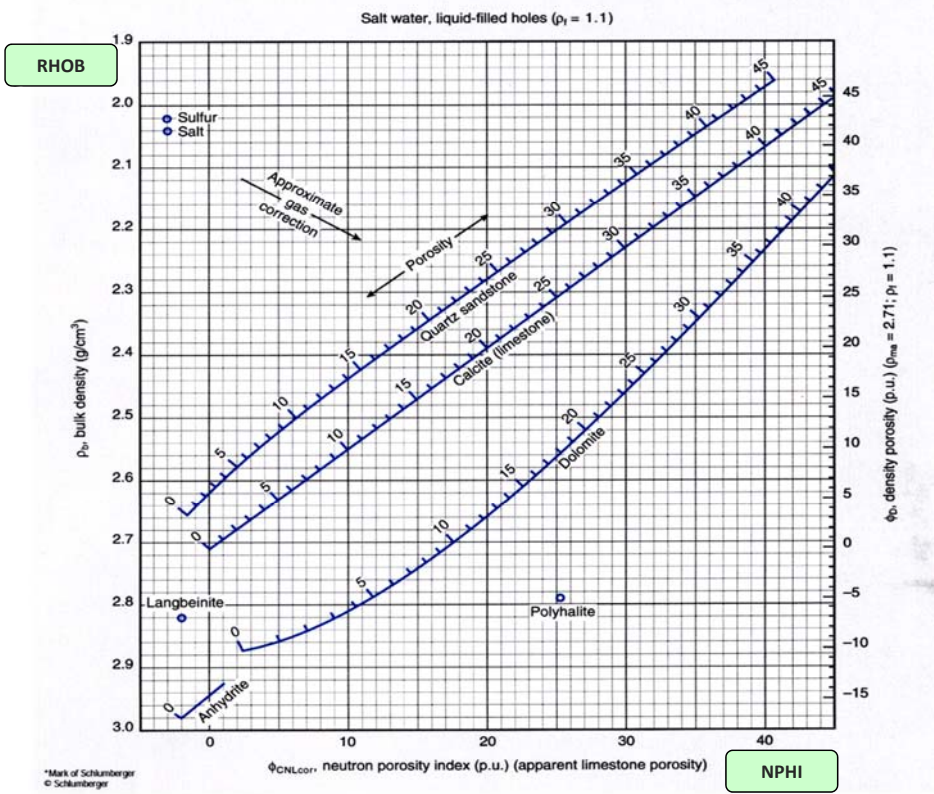


Density-Neutron Crossplot (NPHI) 2/2

Porosity and Lithology Determination from
Formation Density Log and CNL* Compensated Neutron Log
For CNL logs before 1986, or labeled NPHI

CP-1d

RHOB-NPHI
CP-1d
Rhofl = 1.1



(Schlumberger)

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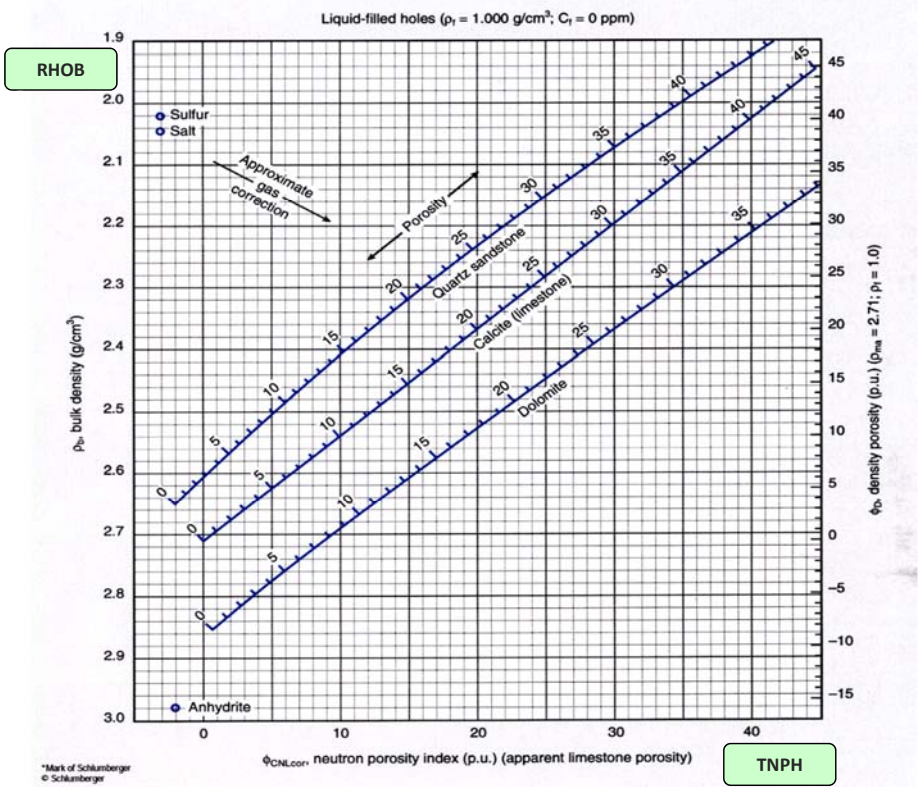
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Density-Neutron Crossplot (TNPH) 1/2

Porosity and Lithology Determination from
Litho-Density* Log and CNL* Compensated Neutron Log
For CNL curves after 1986 labeled TNPH

CP-1e

RHOB-TNPH
CP-1e
Rhofl = 1.0



(Schlumberger)

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Main Logging Tool Response in Sedimentary Minerals

MAIN LOGGING TOOL RESPONSE in Sedimentary Minerals (1/2)

Group	Name	Formula	ρ	Φ	Φ	Φ^*	DTc	DTs	Pe	U	ϵ	Tp	GR	Σ
			log	SNP	CNL	APS	comp	shear						
			g/cm3	p.u.	p.u.	p.u.	μ s/ft	μ s/ft	barn/e		farad/m	nsec/m	API	C.U.
Silicates														
	Quartz	SiO ₂	2,64	-1	-2	-1	56,0	88,0	1,80	4,8	4,65	7,2		4,3
	Opal (3,5% H ₂ O)	SiO ₂ (H ₂ O) ₁₂₀₀	2,13	4	2		58		1,8	3,7				5,0
Carbonates														
	Calcite	CaCO ₃	2,71	0	0	0	49,0	88,4	5,1	13,8	7,5	9,1		7,1
	Dolomite	CaCO ₃ ,MgCO ₃	2,85	2	1	1	44,0	72	3,1	9,0	68	8,7		4,7
	Siderite	FeCO ₃	3,89	5	12	3	47		15	57	6,8-7,5	8,8-9,1		52
Feldspars-Alkali **														
	Orthoclase	KAlSi ₃ O ₈	2,52	-2	-3		69		2,9	7,2	4,4-6,0	7,0-8,2	~ 220	16
	Anorthoclase	KAlSi ₃ O ₈	2,59	-2	-2				2,9	7,4	4,4-6,0	7,0-8,2	~ 220	16
	Microcline	KAlSi ₃ O ₈	2,53	-2	-3				2,9	7,2	4,4-6,0	7,0-8,2	~ 220	16
Feldspars-Plagioclase **														
	Albite	NaAlSi ₃ O ₈	2,59	-1	-2	-2	49	85	1,7	4,4	4,4-6,0	7,0-8,2		7,5
	Anorthite	CaAl ₂ Si ₂ O ₈	2,74	-1	-2		45		3,1	8,6	4,4-6,0	7,0-8,2		7,2
Micas **														
	Muscovite	KAl ₂ (Si ₃ AlO ₁₀ OH) ₂	2,82	12	~ 20	~ 13	49	149	2,4	6,7	6,2-7,9	8,3-9,4	~ 270	17
	Glauconite	K ₂ (Mg,Fe) ₂ Al ₂ (Si ₄ O ₁₀ OH) ₂	2,86		~ 38	~ 15			4,8	14				21
	Biotite	K(Mg,Fe) ₂ AlSi ₃ O ₁₀ (OH) ₂	~2,99	~11	~ 21	~ 11	50,8	224	6,3	19	4,8-6,0	7,2-8,1	~ 275	30

* APS porosity derived from near-to-array ratio (APLC)

** Mean value, which may vary for individual samples

ρ : Density
 Φ : Neutron Porosity (p.u. : Porosity units)
DT : Slowness (C : Compressionnal S : Shear)
Pe : Photo-electrical Factor

Values from Schlumberger Log Interpretation Charts 1998
Appendix B

ϵ : Dielectric Permittivity
Tp : Electromagnetic Propagation Time
GR : Natural Radioactivity
 Σ : Capture Cross Section

Main Logging Tool Response in Sedimentary Minerals

MAIN LOGGING TOOL RESPONSE in Sedimentary Minerals (2/2)

Group	Name	Formula	ρ	Φ	Φ	Φ^*	DTc	DTs	Pe	U	ϵ	Tp	GR	Σ
			log	SNP	CNL	APS	comp	shear						
			g/cm3	p.u.	p.u.	p.u.	μ s/ft	μ s/ft	barn/e		farad/m	nsec/m	API	C.U.
Clays **														
	Kaolinite	Al ₂ Si ₂ O ₁₀ (OH) ₂	2,41	34	~ 37	-34			1,8	4,4	~ 5,8	~8,0	80-130	14
	Chlorite	(Mg,Fe,Al) ₂ (Si,Al) ₄ O ₁₀ (OH) ₂	2,76	37	~ 52	-35			6,3	17	~ 5,8	~8,0	180-250	25
	Illite	K _{1-1,5} Al ₄ (Si _{7-8,5} Al _{1-1,5})O ₂₀ (OH) ₂	2,52	20	~ 30	-17			3,5	8,7	~ 5,8	~8,0	250-300	18
	Montmorillonite	(Ca,Na) ₂ (Al,Mg,Fe) ₂ (Si,Al) ₄ O ₂₀ (OH) ₂ (H ₂ O) ₂	2,12		~ 60	-60			2,0	4,0	~ 5,8	~8,0	150-200	14
Evaporites														
	Halite	NaCl	2,04	-2	-3	21	67	120	4,7	9,5	5,6-6,3	7,9-8,4		754
	Anhydrite	CaSO ₄	2,98	-1	-2	2	50		5,1	15	6,3			12
	Gypsum	CaSO ₄ (H ₂ O) ₂	2,35	50+	60+	60	52		4,0	9,4	4,1	6,8		19
	Sylvite	KCl	1,86	-2	-3				8,5	16	4,6-4,8	7,2-7,3	500+	565
	Carnalite	KClMgCl ₂ (H ₂ O) ₆	1,57	41	60+				4,1	6,4			~ 220	369
	Polyhalite	(K ₂ SO ₄) ₂ MgSO ₄ (CaSO ₄) ₂ (H ₂ O) ₂	2,79	14	25				4,3	12			~ 220	24
	Barite	BaSO ₄	4,09	-1	-2				267	1090				6,8
Oxidates														
	Hematite	Fe ₂ O ₃	5,18	4	11		42,9	79,3	21	111				101
	Magnetite	Fe ₃ O ₄	5,08	3	9		73		22	113				103
	Limonite	FeO(OH)(H ₂ O) _{2,05}	3,59	50+	60+		56,9	102,6	13	47	9,9-10,9	10,5-11,0		71
Sulfides														
	Pyrite	FeS ₂	4,99	-2	-3		39,20	62,10	17	85				90
Coals														
	Anthracite	CH ₃₅₈ N ₂₀₀ O ₈₂₂	1,47	37	38		105		0,16	0,23				8,7
	Bituminous	CH ₂₅₃ N ₂₁₅ O ₈₇₈	1,24	50+	60+		120		0,17	0,21				14
	Lignite	CH ₈₄₉ N ₂₁₅ O ₂₁₁	1,19	47	52		160		0,20	0,24				13

* APS porosity derived from near-to-array ratio (APLC)

** Mean value, which may vary for individual samples

ρ : Density
 Φ : Neutron Porosity (p.u. : Porosity units)
DT : Slowness (C : Compressionnal S : Shear)
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